CALIFORNIA
ENERGY
COMMISSION

FORMS AND INSTRUCTIONS FOR THE ELECTRICITY RESOURCES AND BULK TRANSMISSION DATA SUBMITTAL

Prepared in Support of the 2005 Integrated Energy Policy Report

COMMITTEE REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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DISCLAIMER

This report was prepared by the California Energy Commission's Integrated Energy Policy Report (IEPR) Committee to be consistent with the objectives of the 2003 and 2004 IEPR, Energy Action Plan and various other State policies, regulations and legislation. The report is scheduled for adoption on January 19, 2005. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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Background

This report describes information on electricity and transmission planning that is needed by the California Energy Commission (Energy Commission) to prepare its biennial assessments. This report also provides forms with instructions that define what electricity resource and bulk transmission data must be submitted by load-serving entities and transmission owners.

The Energy Commission is directed by Public Resources Code (PRC) sections 25300-25323 to conduct regular assessments of all aspects of energy demand and supply. These assessments will be included in the *Integrated Energy Policy Report (Energy Report)*, and they serve as the foundation for analysis and policy recommendations to the Governor, Legislature, and other agencies. The broad strategic purpose of these policies is to conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety. In addition, Public Resources Code sections 25216 and 25216.5 provide broad authority for the Energy Commission to collect data and information "on all forms of energy supply, demand, conservation, public safety, research, and related subjects."

To carry out these energy assessments, the Energy Commission is authorized to require submission of historical data, forecast data and assessments from market participants in California.

The Energy Commission is preparing to undertake assessments for the *2005 Energy Report*. These assessments will provide a foundation for the analysis and recommendations of the *2005 Energy Report*, including resource assessment and analysis of progress towards energy efficiency, demand response and renewable energy goals. The forecasts will also serve as a reference case in the 2006 procurement plan proceeding at the California Public Utilities Commission (CPUC), and in the 2005 controlled grid study by the California Independent System Operator (CA ISO). Energy Commission demand and supply assessments are also used in the *California Gas Report*. This report provides instructions for completing electricity supply and bulk transmission data submittals using common terms and conventions.

General Instructions

Who Must File, What Must be Filed, and When

These forms and instructions provide direction to parties for filing electricity resource and transmission planning information. In adopting these forms and instructions, the Energy Commission is specifically requiring the relevant parties to file certain electricity supply information by March 1, 2005,and certain transmission planning information by April 1, 2005. In addition, the *Energy Report* Committee plans to hold an additional workshop on February 15, 2005 to review staff's proposal for additional information relating to key scenarios and uncertainties that parties will be required to file by April 1, 2005. Following that workshop, the Committee will issue an order that directs the relevant parties to file that additional information by April 1, 2005, including additional direction or revisions and errata to these forms and instruction that are necessary. The Committee's order will be brought to the Energy Commission for adoption.

Electricity Supplies

Every Load Serving Entity (LSE) in the state with a peak retail load equal to or greater than 200 MW in either of the two calendar years prior to the filing date is required to file the electricity supply information requested on each form in accordance with the accompanying instructions.[1] For purposes of this filing requirement, LSE means every Investor-Owned Utility (IOU), Publicly Owned Utility (POU), Electric Service Provider (ESP), and Community Choice Aggregator (CCA) doing business in California. The electricity supply information is identified on the following forms, which are included with these instructions:

- S-1 Capacity Resource Accounting Table,
- S-2 Energy Balance Accounting Table,
- S-3 Generic Renewable Capacity and Energy Locations,
- S-4 Projected QF Energy and Costs, and
- S-5 Bilateral Contracts.

All LSEs that served peak loads of 200 MW or more in either 2003 or 2004 are also required to file a written 10-year electricity supply plan with the information requested in the instructions below on 10-year resource plans. This information explains what is in each LSE's reference case.

Hourly Generation Data

In addition, all LSEs that have contracts with Qualifying Facilities (QFs) are asked to provide hourly data on QF energy purchases for calendar years 2003 and 2004. For individual QF contracts with available capacity of less than 10 MW, hourly generation values should be aggregated by technology.

The Energy Commission also asks large LSEs to submit hourly wind generation data for calendar years 2003 and 2004. LSEs that served peak loads of less than 200 MW in both 2003 and 2004 may ask to be exempt from this data request.

The Energy Commission also requests that merchant wind generators larger than 10 MW (nameplate) report their hourly injections into the transmission grid during calendar years 2003 and 2004.

[1] The Energy Commission reserves the right to request filings from power pools whose members, in aggregate, have a non-coincident peak load in excess of 200 MW.

The Energy Commission requests seven utilities to provide hourly generation data on hydroelectric plants that they own. Generation data is requested for years 1998 through 2004. The utilities subject to this request are:

- Hetch Hetchy Water and Power/City and County of San Francisco PUC
- Imperial Irrigation District (IID)
- Los Angeles Department of Water and Power (LADWP)
- Metropolitan Water District (MWD)
- Sacramento Municipal Utility District (SMUD)
- Turlock Irrigation District (TID)
- U.S. Bureau of Reclamation (USBR)

Transmission Planning

All transmission-owning LSEs are required to file a general description of their transmission planning and permitting process. Agencies can submit data for their members. For example, the Transmission Agency of Northern California may file on behalf of several transmission-owning LSEs. When a transmission project is planned by a non-LSE, the LSE owning the facility to which the project interconnects will be responsible for filing the required information.

All transmission-owning LSEs that are planning strategic bulk transmission project upgrades are required to provide the project information requested on the transmission forms or report specifications. This requirement applies to all projects over 100 kV in size that would operate by 2016. Transmission Form 1 and 2 define the information that is required for projects that are over 100 kV but less than $100 million. For projects over $100 million, the instructions for “Form 3” define the topics to be reported on, though the actual format to be followed for these complex projects as at the discretion of filers.

When to File

LSEs are asked to submit the following data by March 1, 2005:

- Electricity Supply Forms S-1 through S-5 for their reference case
- Hourly Generation Data from QF, Wind and Hydroelectric resources

LSEs are also asked to submit the following transmission-related information by April 1, 2005:

- Transmission Plans by all transmission-owning LSEs
- Transmission Project forms

In addition, the Committee will direct LSEs to file additional data by April 1, 2005. The final requirements for this additional data will be established in a Committee Order following a February 15 workshop that addresses scenarios and uncertainties that should be evaluated in the *Energy Report* proceeding. These instructions include the Energy Commission staff's proposal for these additional filings (see the section on Ten-year Resource Plans). The staff proposal will serve as a basis for discussion at the February workshop and identify the following information:

- Electricity Supply Forms S-1 through S-5 by IOUs for their preferred resource plans
- Electricity Supply Forms S-1 through S-5 by IOUs, LADWP & SMUD for an Accelerated Renewable Resource scenario
- Ten-Year Resource Plans by all LSEs

Differential Reporting Requirements

The information requested differs depending on whether the LSE is an Investor-Owned Utility (IOU), a municipal utility[2], or an Energy Service Provider (ESP). This difference stems from different requirements imposed upon each class of LSE by the Legislature and state agencies, and materials created by each class in the course of doing business. While a single format is presented in the sample forms accompanying this document, the detail provided will vary by class of LSE.

IOUs are asked to submit information that is not requested from other LSEs: information related to energy efficiency, demand response, qualifying facilities (QFs), and Department of Water Resources (DWR) contracts.

Municipal utilities and ESPs are not required to provide estimates of the capacity savings associated with energy efficiency, price-sensitive demand response, or distributed generation. They may enter estimates as line-item entries if they wish to rely upon such resources in the future. Alternatively, projections by municipal utilities and ESPs regarding these values may be embedded in their peak demand estimates.

Small and Medium Utility Exemptions

For the 2005 *Energy Report*, small- and medium-sized LSEs will be exempt from filing a 10-year resource plan if they submit a letter asking for this exemption. Small- and medium-sized LSEs will also be exempt from filing the requested forms (S-1 through S-5) on electricity supply resources if they make a request in writing for this exemption. However, these same LSEs are *not* exempt from filing transmission project plans.

The terms Investor-Owned Utility and IOU refer to all six state-regulated corporations that provide bundled electricity service to retail customers in California. By definition, this includes:

[2] This term is intended to include irrigation and water districts and authorities, community choice aggregators, and power pools.

- Pacific Gas and Electric Company (PG&E),
- Southern California Edison Company (SCE),
- San Diego Gas and Electric Company (SDG&E),
- PacifiCorp,
- Sierra Pacific, and
- Bear Valley Electric Service.

The three smallest IOUs are eligible to request the exemption described above. In practice, therefore, the Energy Commission anticipates that these instructions to Investor-Owned Utilities will only apply to the largest three IOUs: PG&E, SCE, and SDG&E.

Submittals and Due Date

The required forms must be submitted to the Energy Commission by March 1, 2005 or April 1, 2005, respectively. For both filings, parties are requested to submit a cover letter along with diskette or compact disk containing:

- Data on specified forms
- Reports in Microsoft Word or Adobe Acrobat
- Hourly Generation Data in Microsoft Excel

Submit this information to:

California Energy Commission
Docket Office
Attn: Docket 04-IEP-01-D
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

To expedite the review, comparison, and assessment process, an Excel template with data forms is available on request. While this template is the preferred format, participants may provide these results in a different format as long as the equivalent information is provided timely and clearly labeled.

General questions about either the forms or instructions should be directed to Al Alvarado at aalvarad@energy.state.ca.us or (916) 654-4749.

More specific questions may be directed to other staff:

IOUs	David Vidaver	dvidaver@energy.state.ca.us	916-654-4656
POUs	Jim Woodward	jwoodwar@energy.state.ca.us	916-654-5180
Transmission	Mark Hesters	mhesters@energy.state.ca.us	916-654-5049
Scenarios	Mike Jaske	mjaske@energy.state.ca.us	916-654-4777
Confidentiality	Fernando DeLeon	fdeleon@energy.state.ca.us	916-654-4873

Confidentiality

Certain categories of data submitted to the Energy Commission can automatically be designated as confidential. The types of data that are eligible for this designation, and the process for obtaining this confidential designation, are specified in Section 2505(a)(5) of the Energy Commission's regulations (found in Title 20 of the California Code of Regulations).

If a filer believes that data should be confidential even though it is not included in one of these categories, the filer should submit an application to designate the data as confidential. The Executive Director will review the application and make a determination about the confidential status of the data. In addition, filers should be aware that Energy Commission staff may aggregate and disclose some confidential data. Both historic and forecast energy sales data may be disclosed if reported at the following levels:

- For individual ESPs, data aggregated at the statewide level by major customer sector;
- For the sum of all ESPs, data aggregated at the service area, planning area, or statewide levels by major customer sector;
- For the total sales of the sum of all electric retailers, data aggregated at the county level by major generator, utility, and electric service provider groups as these groups are defined by the U.S. Census Bureau in their North American Industry Classification System (NAICS) and Standard Industrial Classification (SIC) tables.

Scope of Supply Resources Forms

Purpose

The purpose of these Forms and Instructions is to understand LSE planning assumptions, evaluate LSE forecasts, and identify statewide trends and progress towards addressing various concerns. The forms also request data that will be needed for analyzing electricity system issues.

Deliverability of Resources

Electricity resources must be deliverable to the respective LSE load centers to be fully counted as existing or planned resources. The one notable exception to this general deliverability requirement is the long-term Sempra contract with the California Department of Water Resources (DWR), a contract that is not tied to specific generating plants and which allows a delivery point anywhere in the state of California. Each LSE is expected to perform deliverability screening, filtering, or other appropriate criteria for matching loads with resources. However, the disclosure of these criteria is not requested on these forms. Unlike past Electricity Reports, the supply resources forms do not address transmission facilities or transmission planning.

Deliverability needs are not being overlooked or minimized. The Energy Commission recognizes that costs of transmission congestion can be substantial. New transmission facilities face intractable difficulties in siting approval and cost allocation. This can be a barrier to development of new generation supply resources, regardless of whether they are utility-owned, merchant-built, or eligible renewables.

Information on the major upgrades to the bulk power transmission system must include a discussion of the benefits, costs, and risks involved, while examining connected yet interchangeable aspects of reliability, rates, and environmental performance. Several active proceedings are working to establish agreements and decisions in this area. This includes CPUC umbrella proceedings on the Transmission Assessment Process (R.04-01-026) and Transmission Planning (I.00-11-001). Future *Energy Report* cycles are likely to request broad long-term data and analysis on transmission needs and systems assessments.

Definitions and Aggregated Data

Definitions

All LSEs in California are expected to use reasonably consistent and compatible terms and counting conventions for existing and planned electricity supply resources. This consistency is needed to facilitate a general evaluation of statewide supply adequacy, including some limited assessments of coincident peak supply needs within specific control areas, primarily that of CA ISO.

Existing Demand Side Management (DSM) programs that are not dispatchable are incorporated into the demand forecast, and are not considered supply resources.

Planned resources are those that an LSE deems either most likely or most preferred as additions to the portfolio. For IOUs, planned resources are those specific facilities and contracts that the CPUC has approved but are not yet on line (Mountain View, Otay Mesa, Palomar, and RAMCO). In other words, they are simply committed resources. For other LSEs, they are resources that are either committed or which the LSE has a reasonable expectation of committing to. This would include SMUD's Cosumnes 1 power plant and also Cosumnes 2 if SMUD presently intends to go forward with the second unit. The listing of planned resources should reflect the most probable long-term resource plan for an LSE and its preferred "loading order,"[3]

[3] For example, the *2003 Energy Action Plan* adopted the following loading order. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and

especially where an LSE must add new resources to accommodate forecast load growth or capacity retirements.

Hydroelectric generation is considered an existing resource for the duration of time that an LSE has legal authority to integrate production of forecast energy and dependable capacity. After the expiration date of a FERC license, operating agreement, or integration agreement, it would be a planned resource if the LSE expects to retain it in its portfolio.

The term “Planned Resources” can include physical and contractual resources about which there is any degree of uncertainty due to regulatory, financial, or legislative risks. For example, scheduling of CPUC procurement approvals, along with anticipated delays and expected appeals, might keep a specific planned Resource from becoming a committed resource for many months. The distinction between planned and committed resources was important in the past, such as the Energy Commission’s 1994 Electricity Report; however, this distinction is not important for data collection for the 2005 *Energy Report*.

Aggregated Data

Each individual resource, existing or planned, physical or contractual, should be a line-item entry on forms S-1 and S-2, with numeric entries for those months that the LSE expects to own, control, or contract with that resource. For completing forms S-1 and S-2, there are two exceptions to this general requirement. First, all utility-controlled hydroelectric assets (non-QF) should be aggregated into two categories (more or less than 30 MW nameplate). Second, QF contracts should be aggregated by technology: natural gas – cogen, biofuels, geothermal, small hydro, solar, wind, and other.

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distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to “get to scale,” the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

Supply Form S-1: Dependable Capacity Resource Accounting Table (MW)

Scope

LSEs are asked to estimate how much power (in MW) is needed to serve monthly peak retail customer load, plus reserves and other obligations, as well as identify how much power will come from electricity supply resources. These estimates are required for all months of the forecast period, January 2006 through December 2016. LSEs are requested to provide these data on Supply Form S-1, Dependable Capacity Resource Accounting Table, also called a CRATs table. The data submitted by each LSE on Form S-1 should correspond one-to-one with the data submitted on the Energy Balance table, Form S-2.

Form S-1 will provide a forecast of non-coincident peak demand in megawatts for each Load Serving Entity (LSE), followed by a summary of how that demand will be met with existing, planned, and generic resources.

Dependable Capacity (MW)

All capacities should be reported as dependable capacity, not nameplate. Capacity values should not be adjusted for expected forced outages. However, specific forecast months should incorporate capacity reductions for scheduled outages such as annual hydro maintenance in November, and scheduled nuclear shutdowns for refueling.

Please report the amount of capacity from each generation source, measured at the busbar, which is considered firm and reliable for meeting peak planning loads. For intermittent resources without flexible dispatch (such as wind), dependable capacity estimates should reflect the non-firm nature of this supply. LSEs are asked to explain how these values are determined. For exchanges and imports, dependable capacity is the amount that can be counted on with a high degree of certainty for meeting the LSE's non-coincident peak demand. Following the CPUC decision on resource adequacy and "qualifying capacity," energy supply contracts with provisions for liquidated damages, instead of replacement power obligations on the supplier, may only be counted as dependable capacity through 2009.

Peak Demand Calculations (MW)

Line 1 Forecast Total Peak Demand

On line 1, all LSEs are asked to forecast their non-coincident peak demand for each month in the forecast period. This number, in MW, must include all power needed to serve retail loads along with the power needed to deliver supplies to loads. Therefore, these peak demand estimates must include allowances for transmission and distribution line losses, station loads of utility-controlled resources, and unaccounted for energy (UFE).

IOUs shall include the total peak demand that is met (delivered) by their Utility Distribution Company (UDC). This capacity number is larger than the IOU obligation to serve in their role as a LSE. The UDC total peak demand includes load that is served by ESPs, amounts that are listed on line 4 below. Peak Demand estimates on line 1 should not include amounts of peak capacity needed for sales (shown on line 11) or for a planning reserve margin (line 10).

LADWP, SMUD, and IID are municipal utilities who also operate independent control areas that are entirely within California. Some Direct Access customers may be located within each of these municipal control areas. If so, these three POUs are requested to identify total peak forecast demand on line 1 that includes DA load. Forecast amounts of DA load should also be listed on line 4.

Line 2 ESP Peak Demand: Existing Contracts

On line 2, ESPs are asked to indicate the load obligations that arise from existing customers. ESPs are asked to distinguish between expected loads of those customers under contract and a residual which represents both new customers and the load associated with the anticipated renewal or extension of contracts with existing customers. Enter the peak demand for customers under current contracts, including those contracts with start dates after the filing date to which the ESP has committed. This demand should be coincident with the peak faced by the ESP; i.e., the sum of this value and that entered on line 3 (ESP Peak Demand - New & Renewed Contracts) should equal the value entered on line 1.

Line 3 ESP Peak Demand: New & Renewed Contracts

On line 3, ESPs are asked to estimate total monthly capacity needs that arise from new customers, plus contract renewals and extensions to serve existing customers. This forecast should be the “most likely” case. Enter the peak demand for likely new customers and customers who are forecast to renew or extend existing contracts. This demand should be coincident with the peak faced by the ESP; i.e., the sum of this value and that entered on line 2 (ESP Peak Demand - Existing Contracts) should equal the value entered on line 1.

Line 4 Direct Access (-)

On line 4, IOUs, LADWP, SMUD, and IID should enter the forecast peak demand for all DA customers in the service territory of their Utility Distribution Company (UDC). For the reference case in the 2005 *Energy Report* cycle, each IOU should assume that there is no additional migration between IOU and DA service. The municipal utilities should estimate DA loads according to their own assumptions and assessments. If other municipal utilities believe that some additional existing loads in their service territories will choose an ESP (above and beyond what ESPs may presently be serving), then these amounts should be shown on line 4.

Line 5 Community Choice Aggregation & Departing Municipal Load (-)

IOUs are asked to identify a particular amount of Community Choice Aggregation (CCA) and Departing Municipal Load (DML) from a specified range of possibilities. As likely CCA/DML values are both very uncertain and are apt to be utility-specific, each IOU is asked to choose a CCA/DML level for its reference case that meets the following requirements. The IOU should assume that departure begins no earlier than 2007 and not later than 2013. Total departure over this period should be at least 4% of bundled customer load and no greater than 10%. Enter these amounts of departing load on line 5.

Municipal utilities are asked to incorporate into their total peak load estimates (line 1) their assumptions regarding increased loads that may depart from IOU service.

Line 6 Uncommitted Price Sensitive DR Programs (-)

Price-sensitive demand response goals for the IOUs were established in D.03-06-032 (p. 10). These are 4% of the annual peak demand in 2006, and 5% in 2007 and thereafter.[4] The IOUs are asked to assume that these targets will be met. The committed portion of price sensitive demand response should be included in the base load forecast, and the remaining, uncommitted portion should be shown on line 6 in the CRATs table.

Line 7 Uncommitted Energy Efficiency (2009-2016) (-)

The CPUC established energy efficiency targets for both peak demand and energy for each of the IOUs (in D.04-09-060). The three large IOUs are again asked to assume these targets will be hit precisely in the reference case. The energy efficiency targets represent the cumulative energy savings expected from IOU energy efficiency programs implemented between 2004 and 2016. As such, a share of the savings in these targets includes committed savings from program funding already approved by the CPUC for 2004 and 2005. These savings should be reflected in the retail load and sales forecasts submitted. For IOUs, the capacity and energy share should be provided as a line item on line 7 in the CRATS table, and on line 6 in the Energy Balance table.

Line 8 Distributed Generation (-)

The IOUs are asked to provide an estimate of uncommitted Distributed Generation (DG) on the customer side of the meter as a separate line item. Enter this forecast amount on line 8. This number should represent new amounts of Self Generation that would be subtracted from future IOU load obligations. The CPUC has not established a target for customer-side DG. Municipal utilities and ESPs should incorporate DG adjustments into amounts shown on line 1.

The broadest possible definition of DG includes all Self Generation and cogeneration, along with smaller independent systems capable of supplying most of the electrical needs of residential and small commercial customers. Self Generation capacity includes capacity used by the project for on-site demands, and any capacity sold by the project to third parties. Self Generation capacity is normally not available to the LSE.

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[4] It was further established in D. 04-06-011 that interruptible and emergency programs do not qualify to satisfy these price-responsive demand goals.

Two additional DG numbers are *not* being requested on line 8. One number is the LSE's estimate of total DG and Self Generation that is produced and used concurrently on the customers' side of the meter. The other number is the amount of DG/Self Generation power injected into the grid that can be counted on with a high degree of certainty for meeting the LSE's non-coincident peak demand. Those two numbers can be listed elsewhere on the form under QF contracts, renewable contracts, or other bilateral contracts, and may be explained in footnotes if LSEs desire to do so.

Line 9 Net Peak Demand for Bundled Customers

IOUs are asked to take the amount on line 1, and subtract the amounts shown on lines 4, 5, 6, 7, and 8.

POUs are asked to take the amount on line 1, and subtract the amount (if any) on line 4. For POUs and ESPs, if there are no amounts shown on lines 4-8, enter on line 9 the same amount shown on line 1.

Line 10 Net Peak Demand + 15% Planning Reserve Margin

To determine amounts on line 10, IOUs and ESPs shall multiply the sum in line 9 by 115%. Pursuant to D. 04-101-050, IOUs and ESPs are now required to meet a 15% planning reserve margin for capacity up to 12 months ahead, beginning on September 30, 2005 for 5 summer months in 2006.[5] By conceptually extending this requirement to the entire forecast period, IOUs and ESPs are asked to show this as part of the capacity needed to reliably serve load obligations. Municipal utilities are encouraged to use the same 15% planning reserve margin. However, if a POU consistently uses a different number for its resource planning and procurement responsibilities, then that number should be used to calculate line 10.

Line 11 Firm Sales Obligations

On line 11, list total amounts of firm capacity that the utility has contracted to deliver to other parties, both within the LSE's control area and beyond. If this capacity obligation is measured at some distant delivery point, add an appropriate amount to accommodate line losses and station load. If sales obligations include reserves, be sure to add 15% to the total sale obligations.

Line 12 Firm Peak Resource Requirement

Add line 10 to line 11 to calculate amount of capacity here called the firm peak resource requirement. Enter this amount on line 12.

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[5] Meeting this reserve requirement in 2006 was directed in R.04-04-003.

Existing and Planned Resources

Utility-Controlled Fossil and Nuclear Resources

Utility-Controlled Resources

Utility-controlled resources are those that an IOU or POU can dispatch, schedule, or integrate. Integration means the ability to use the generation output of facilities such as cogeneration, “must-take” wind, and “run of river” hydro. Resource data about facilities controlled by one LSE but owned by another, such as an irrigation district, should be reported by the controlling utility. LSEs have the reporting responsibility for generating resources owned by non-LSE irrigation and water districts. For example, PG&E should include Placer County Water Agency, the City and County of San Francisco (Hetch Hetchy), and other irrigation districts and water agencies with generation that is dispatched or integrated by PG&E.

Fossil and Nuclear Resources

This section asks for forecast data on fossil and nuclear resources that the LSE owns or controls. This definition includes ownership shares in San Onofre nuclear generating stations, and power purchase agreements for natural-gas fired plants such as Mountainview and Otay Mesa.

Beginning on line 13, submit one row of dependable capacity forecast data for each fossil and nuclear plant. From this point forward on Form S-1, the line numbers on LSE submittals will not match those shown on the forms. The CRATS table, Form S-1, provides a generic illustration with minimal direction, so that line 13 begins the listing of individual fossil and nuclear resources. Line 14 shows an ellipse representing one row for other plants in the series, and line 15 is for the last plant in the series, “Unit N.” If the LSE controls a large number of resources in this section, please list them on a separate tab in Excel, and list the totals only on line 16.

Line 13 Unit 1 [List each fossil and nuclear resource.]
Line 14 …..
Line 15 Unit N

Line 16 Total Dependable Fossil and Nuclear Capacity
On line 16, enter the sum of lines 13 through 15 (or on many lines as are needed to list each and every utility-controlled fossil and nuclear generating facility).

Utility-Controlled Hydroelectric Resources (1-in-2)

Unlike the section on fossil plants above, LSEs are not being asked to report energy and capacity estimates for individual hydroelectric generating plants that they own or control.

Lines 17 and 18 on Form S-1 ask for the total dependable capacity of all LSE-controlled hydroelectric resources under median (1-in-2) hydrological conditions, with one notable exception. The exception is Hoover Dam because the U.S. Bureau of Reclamation (USBR) publishes highly reliable forecasts of capacity and energy looking forward 24 months. Therefore, LSEs with Hoover entitlements should use the latest USBR forecast for 2006, and use 1-in-2 estimates for 2007 and beyond.

During the 2006-2016 forecast period, FERC licenses will expire for about 5,000 MW (Nameplate) of existing hydroelectric resources. LSEs are instructed to identify appropriate reductions in capacity and energy considered most probable. The most probable outcomes for hydro relicensing must consider eventual settlement negotiations, new FERC license conditions, and mandatory conditions set by the State Water Resources Control Board (SWRCB) for water quality certification according to Section 404 of the federal Clean Water Act. Forecast capacity or energy reductions as a result of relicensing could easily be in the range of 4% to 13%.

Line 17 Total for all plants over 30 MW nameplate

On line 17, provide the total dependable capacity of all hydro resources over 30 MW nameplate. This distinction follows FERC definitions of large and small hydro. Thirty MW is also the upper plant size limit that is eligible to be counted as a producer of "renewable energy" by IOUs, ESPs, and CCAs under California's Renewable Portfolio Standard. However, if a plant has more than one turbine, and each turbine has a distinctly separate water supply (such as PG&E's 44 MW Salt Springs powerhouse), then each turbine that is 30 MW or less can be counted with state-defined renewables on line 18.

Line 18 Total for all plants 30 MW nameplate or less

On line 18, provide the total dependable capacity for all hydro resources equal to or less than 30 MW nameplate.

Line 19 Hydro Derate for 1-in-5 conditions (-)

Line 19 asks for a total derate number (stated as a positive number) to indicate the reduction in dependable capacity going from 1-in-2 (median year) hydrological conditions to 1-in-5 dry conditions (dry hydro year). LSEs are asked to provide one total derate number for all hydro resources in their portfolio. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in 4 of the last 5 years, or 16 of the last 20 years, or some similar series considered most appropriate. If future operating conditions and restrictions differ from historic generation patterns, adjust derate numbers to match the most likely future scenario for 1-in-5 dry years. For LSEs with Hoover entitlements, do not derate capacity forecasts for 2006. The 1-in-5 number derate number will be an input to line 21.

For hydroelectric resources, LSEs are asked to provide a total dependable capacity estimate for all resources in its portfolio using 1-in-5 dry hydro conditions. The CPUC has adopted this 1-in-5 dry hydro standard for the IOUs to estimate "qualifying capacity" for hydro in meeting resource adequacy requirements. Following this CPUC standard, a hydro resource must be able to operate during 4 super-peak hours for 3 consecutive days to count as dependable capacity for that month. If individual LSEs use a significantly different definition of dependable capacity, they are asked to footnote these numbers and provide explanatory information.

Line 20 Hydro Derate for 1-in-10 conditions (-)
LSEs are also asked to provide a hydro derate number (stated positively) for their portfolio that represents 1-in-10 dry year conditions. This estimate is for comparative interest and system-wide risk assessment. Do not derate amounts of energy from Hoover Dam that are derived from a published 24-month forecast by the U.S. Bureau of Reclamation.

Line 21 Total Dependable Hydro Capacity
To determine the amount on line 21, add lines 17 and 18 together, and subtract line 19. This amount is the total dependable "dry year" capacity for hydroelectric resources under LSE control.

Existing and Planned Renewable Resources

This section asks for forecast data on individual renewable resources (other than hydro) that are under LSE ownership or control. The data include existing resources and specific, named generating facilities that have been announced. List each generating resource on a separate row, similar to the section above on utility-controlled fossil fuel resources. If an LSE has a large number of renewable resources that it owns or dispatches, these may be listed on a separate tab with the total number brought forward to Form S-1, line 25.

Line 22 Unit 1 (fuel) [List each non-hydro resource.]
Line 23 …
Line 24 Unit N (fuel)

Line 25 Total Renewable Dependable Capacity

Line 26 Total Utility-Controlled Physical Resources
Take total amounts of dependable capacity listed in the three sections above for utility-controlled physical resources. This includes fossil fuel and nuclear resources (line 16), hydro (line 21), and other renewable resources (line 25). Enter the sum of these three numbers on line 26.

Existing and Planned Contractual Resources

List the total dependable capacity by month for each LSE contract that will be available to the IOU during the forecast period. Do not include Utility Distribution

Company wheeling deliveries, such as Direct Access supplies to Stanford University within PG&E distribution territory.

DWR Contracts

The state's three major IOUs are asked to report dependable capacity from specific DWR contracts. The term "DWR contracts" refers to supply contracts negotiated by the California Energy Resources Scheduling office of California Department of Water Resources. These DWR contracts were signed in 2001 during the energy crisis to provide capacity and energy from third parties to meet IOU loads. To avoid the potential for double counting, do not report these contracts elsewhere on the forms. List each contract on a separate row, starting with line 27, and sum the total on line 30.

Line 27 Contract A
Line 28 ….
Line 29 Contract N

Line 30 Total DWR Contracts

QF Capacity Summary by Fuel/Technology Type

Beginning on line 31, provide total amounts of dependable capacity from Qualifying Facilities (QFs) as defined by the Public Utilities Regulatory Policy Act (PURPA), summarized by fuel/technology type. The section on QF contract resources does not ask LSEs for data about individual generating resources.

As existing QF contracts expire, these resources could remain available to LSEs under terms of new QF contracts under PURPA auspices. Some QF resources may continue doing business by winning contracts under competitive renewable procurement solicitations. Therefore, the same existing QF renewable resources could be listed on lines 32-36 for the early years of the forecast period, and be listed again in later years on lines 39-42. To the extent that an IOU assumes current QF resources will continue to be under contract, these resources should continue to be counted on lines 32-36.

The dependable capacity total for QF resources includes everything that the LSE deems likely to be available during a specific month. Estimates of QF dependable capacity should be based on average historical generation during peak hours as defined in Standard Offer 1 contracts, which is Noon to 6 PM summer weekdays excluding holidays. Dependable capacity includes both firm contract capacity and that portion of as-available contract capacity that the LSE deems likely to be available on any given peak hour, contracts notwithstanding, based on statistical performance history. Any changes to this methodology and related impacts to the derived values shall be explained in an attachment to the CRATs table.

The IOUs and LADWP are asked to indicate the amounts of dependable capacity and energy expected from QFs through 2016. During this forecast time period, most QF contracts will expire. LSEs need not assume that existing QF contracts will be renewed or extended beyond those for which an extension has already been mandated. PG&E and SCE shall provide a narrative scenario in which all of its QFs remain as providers of must-take energy over the forecast horizon.[6] That narrative should be included in the discussion of "Major Uncertainties and Risk Analysis" section of IOU reports on their 10-year plans.

Line 31 Natural gas
Line 31 asks for total capacity of all QF resources powered by natural gas.

Line 32 Biofuels
Line 32 asks for QF resources powered by biofuels, a large generic term including landfill gas, dairy waste, forest products, almond shells, and discarded fast food cooking oils.

Line 33 Geothermal
Line 33 is for all types of geothermal production including dry vapor and dual-flash systems.

Line 34 Small Hydro
Line 34 asks for small hydro QF totals, meaning only those plants rated 30 MW nameplate or less. Provide derated dependable capacity for a 1-in-5 Dry Year.

Line 35 Solar
Line 35 takes in all types of solar resources, including photovoltaic and gas-assisted central station plants.

Line 36 Wind
Line 36 asks for a summary of existing and planned wind QF resources that the LSE knows or expects will be under QF contract terms. New wind resources are not expected to have new QF contracts. New wind should be listed elsewhere on the form, either as a planned renewable resource (line 22 if they are utility-controlled), under renewable contracts (line 39) for identified projects, or as generic renewables (line 52) to meet future targets with facilities that are not yet specifically identified. Provide the dependable capacity total for QF wind on line 36.

Line 37 Other
Line 37 includes all other QF contract generating resources.

Line 38 Total QF Dependable Capacity
On line 38, enter the sum of all QF resources listed on lines 31 through 37.

[6] SDG&E is not asked to provide this assessment due to the small amount of capacity involved in its expiring QF contracts.

Existing & Planned Renewable Contracts

LSEs are asked to list dependable capacity from renewable resources that are acquired to meet renewable procurement targets. This section is mandatory for the three major IOUs, and may also be relevant for other LSEs such as LADWP and SMUD whose governing boards have adopted specific renewable energy goals. Each contract should be named and listed on a separate row beginning with line 39. Capacity data on individual generating facilities, such as wind turbines, is not requested in this section. To *avoid double counting*, do not repeat a listing of contract resources if they are already included in earlier sections on utility-controlled hydro resources or QF contract resources. If an LSE has or projects a large number of renewable contracts, they may be listed on a separate spread sheet, equal to lines 39 to 41.

Line 39 Contract A
Line 40 ….
Line 41 Contract N

Line 42 Total Existing & Planned Renewable Contracts
Add the total capacity of all renewable contract resources starting on line 39, and enter the total on line 42.

Other Bilateral Contracts

All LSEs are asked to list dependable capacity from other bilateral contracts for supply resources that are not already counted in earlier sections on utility-controlled hydro, DWR contracts, QF contracts, and renewable resource contracts. Each bilateral contract should be named and listed on a separate row beginning with line 43. Capacity data on individual generating facilities is not being requested in this section. To avoid double counting, do not repeat a listing of contract resources if they are already included in earlier sections. If an LSE has or projects a large number of Other Bilateral Contracts, they may be listed on a separate spread sheet, equal to lines 43 to 45.

Line 43 Contract A
Line 44 ….
Line 45 Contract N

Line 46 Total Other Bilateral Contracts
Add the total capacity of all other bilateral contract resources starting on line 43, and enter the total on line 46.

Short Term and Spot Market Purchases

Line 47 Short Term and Spot Market Purchases

All LSEs are asked to indicate how much of their monthly non-coincident peak capacity needs could be dependent on short term purchases and by spot market purchases. List these amounts, if any, on line 47 or enter zero. Short term and spot market purchases are defined here to include all procurement that is less than three consecutive months in duration.

Line 48 Total: Existing and Planned Capacity

On line 48, enter the sum of existing and planned electricity supply resources that were counted in earlier sections. The amount to enter on line 48 is the sum of lines 26 (utility-controlled resources), 30 (DWR contracts), 38 (QF contracts), 42 (renewables contracts), 46 (other bilateral contracts), and 47 (short term and spot market purchases).

Dispatchable Load Management Programs

Line 49 Interruptible / Emergency (I/E) Programs

On line 49 IOUs and municipal utilities are asked to enter the load reduction amounts (stated as positive numbers) that should be available from emergency programs. Only interruptible load subject to LSE dispatch should be counted on line 49. In the CA ISO control area, for example, LSEs have cycled residential air conditioners during Stage 2 emergencies to avoid reaching a Stage 3 emergency with forced load shedding. Interruptible and emergency programs need only be considered dependable for 2 consecutive hours in a month. When these programs are called on, the corresponding amount of energy saved is quite small, so there is no comparable line for emergency programs on the energy balance table, Form S-2.

Line 50 Uncommitted Dispatchable Demand Response

On line 50, IOUs are asked to estimate the amount of load reduction (stated as a positive number) that will likely become available from currently uncommitted dispatchable demand response programs. Include curtailable loads and new interruptible tariff schedules but not price responsive demand.

Line 51 Total Capacity with I/E and UDDR

To determine the amount on line 51, take the amount on line 48 (interruptible/emergency programs), subtract line 49 (uncommitted dispatchable demand response), and then subtract line 50. This amount is the LSE’s total dependable capacity including all interruptible, emergency, and dispatchable demand response programs.

Future Generic Resource Needs

Lines 52 through 58 are for non-specific “generic” resources that will be needed to meet forecast load obligations. Most, if not all, LSEs will need to procure additional resources during the next 10 years.

In some instances, LSEs have committed to specific but yet-to-be-built physical resources. All announced projects with names and locations should be listed in earlier sections on utility-controlled resources lines 13 to 26), or contract resources (lines 27 to 46).

Many LSEs have not yet begun to consider specific projects to serve loads after 2010, or if these loads could be better served with physical or contractual resources. During a 10-year planning horizon, many supply and demand uncertainties are compounded, making peak load forecasts and financial investment decisions highly contingent or tentative at best. Nonetheless, the daily and seasonal shapes of LSE load obligations may be reasonably estimated, and each LSE knows its own portfolio of existing and planned resources, and how that portfolio matches up with forecast loads. For projected load and necessary reserves that are *not* covered by existing and planned resources, all LSEs are expected to provide estimates of what would be needed generically to meet the LSE’s obligations. The first such generic resource to be identified is that needed to meet renewable energy retail sales targets (especially the IOUs). After that, all LSEs are asked to identify generic baseload, shaping, and/or peaking resources that will be needed through 2016, and the extent to which generic shaping and peaking resources are needed seasonally or year-round. The amount (MW) of this generic need should be specified by resource type on lines 53 through 58.

Generic Renewable Resources

Line 52 Generic Renewable Resources

On line 52, enter the aggregate dependable capacity expected from renewable resources beyond those specific, named resources that already exist or which are already listed in earlier sections as planned contractual or utility-controlled renewable resources.

For IOUs, this value will be influenced by the RPS that they are asked to assume. For the reference case in the 2005 *Energy Report* cycle, IOUs are asked to assume that in calendar year 2010, 20% of all retail energy sales will have been matched by energy produced from state-defined eligible renewable resources. To ramp up and maintain this 20% renewable energy target (ignoring contributions of large hydro), IOUs may assume that eligible hydro resources are generating under median (1-in-2) hydro conditions.

The IOUs, LADWP and SMUD are also asked to develop a second set of supply numbers, for lines 51 forward, using higher targets after 2010 through 2016 and a higher target in an Accelerated Renewables Scenario to be filed April 1, 2005. (see Accelerated Renewables Scenario as described in the 10-year Resource Plan section)

The values entered on line 52 should be consistent with the entries submitted on Form S-3, generic renewable capacity and energy locations. The IOUs are asked to provide resource plans which enable them to meet a renewable energy target of twenty percent of retail sales by 2010 and maintain purchases at that level through 2016. They are asked to provide their best projections of the energy and associated capacity that will meet these targets by location (ISO zone, control area) and technology (geothermal, biofuels, wind, solar). The IOUs will be filing 10-year renewables plans at the CPUC and the two filings should be compatible.

The IOUs have a conditional mandate to procure renewable resources to meet energy sales targets through 2017. That obligation is conditioned by the availability of Public Goods Charge (PGC) funds that may be needed to make Supplemental Energy Payments (SEP) for eligible contracts resulting from a competitive procurement process. In the future, the trading of Renewable Energy Credits (RECs) sold separately from the associated electricity might also be considered eligible to meet California's RPS obligations. If a viable, liquid, and transparent market for RECs can be created by legislation, that market could significantly reduce the amount of physical resources and transmission that some LSEs, notably SDG&E, might otherwise need to acquire.

The obligation to acquire renewable resources varies considerably among different classes of LSEs (IOUs, municipal utilities, ESPs and CCAs). The nature of this obligation is likely to change considerably over time in numerous ways that are difficult to forecast. LSEs are directed to identify potential RPS scenarios that would strongly affect eligible renewable procurement, and to discuss these effects on Planned Resources in the narrative sections of their response.

Generic Non-Renewable Resources

Line 53 Capacity for Baseload Energy

On line 53, enter the capacity associated with baseload energy needs not met by existing resources, planned resources, or generic renewable resources. Values which are sustained year-round over a long period reflect needs for which the LSE might consider construction, purchase, or a long-term power purchase agreement (PPA) for the output of a baseload resource. Values which are sustained for shorter periods reflect baseload needs for which the LSE might consider a shorter-term energy contract (e.g., all energy, for 7 days x 24 hours, from a 200 MW resource during Q3 of years 2014-2016).

Line 54 Capacity for Load-following and Peaking Energy

On line 54, enter the capacity associated with cyclical energy needs not met by existing resources, planned resources, or generic renewable resources. Values sustained over long periods reflect needs for which the LSE might consider resource construction, resource purchase, or a long-term power purchase agreement with a load-following or peaking resource. Values sustained for shorter periods reflect needs for which the LSE might consider shorter-term contracts for peak and super-peak energy.

Line 55 Load-Following (year-round) Capacity

On line 55, enter the capacity associated with physical, contractual, or demand-side (year-round) resources to meet load following, shaping, or peaking needs.

Line 56 Peaking (seasonal) Capacity

On line 56, enter the capacity associated with contractual or demand-side resources needed to meet peaking capacity needs on a seasonal basis.

Line 57 Total Capacity of Non-Renewable Generic Resources

On line 57, enter the sum of lines 53, 54, 55, plus 56.

Line 58 Total Capacity of Future Generic Resources

On line 58, enter the sum of line 51 plus line 57.

Electricity Resource Planning Form S-1

Dependable Capacity Resource Accounting Table (CRATs) (page 1 of 3)

California Energy Commission

Filing LSE:

Date:

Contact Name:

Contact Number:

	Applies To:	PEAK DEMAND CALCULATIONS (MW):	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
1	All	Forecast Total Peak Demand							
2	ESP	Peak Demand: Existing Contracts							
3	ESP	Peak Demand: New & Renewed Contracts							
4	IOU	Direct Access (-)							
5	IOU	CCA & Departing Municipal Load (-)							
6	IOU	Uncommitted Price Sensitive DR Programs (-)							
7	IOU	Uncommitted Energy Efficiency (2009-2016) (-)							
8	IOU	Distributed Generation (-)							
9	All	Net Peak Demand for Bundled Customers	1 - (sum 4 thru 8)						
10	IOU/ESP	Net Peak Demand + 15% Planning Reserve Margin	Product Line 9 x 1.15						
11	IOU/Muni	Firm Sales Obligations							
12	All	Firm Peak Resource Requirement	Sum 10 + 11						
		EXISTING & PLANNED RESOURCES							
		Utility-Controlled Fossil and Nuclear Resources:							
13	IOU/Muni	Unit 1 [List each fossil and nuclear resource.]							
14	IOU/Muni	…..							
15	IOU/Muni	Unit N							
16	IOU/Muni	Total Dependable Fossil and Nuclear Capacity	Sum 13 thru 15						
		Utility-Controlled Hydroelectric Resources (1-in-2):							
17	IOU/Muni	Total for all plants over 30 MW nameplate							
18	IOU/Muni	Total for all plants 30 MW nameplate or less							
19	IOU/Muni	Hydro Derate (-) for 1-in-5 conditions							
20	IOU/Muni	Hydro Derate (-) for 1-in-10 conditions							

21	IOU/Muni	Total Dependable Hydro Capacity	Sum 17 + 18 - 19						
Electricity Resource Planning Form S-1: Dependable Capacity Resource Accounting Table (CRATs) (page 2 of 3)									
	Applies To:	**Existing & Planned Renewable Resources:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
22	IOU/Muni	Unit 1 (fuel) [List each non-hydro resource.]							
23	IOU/Muni	…							
24	IOU/Muni	Unit N (fuel)							
25	IOU/Muni	Total Renewable Dependable Capacity	Sum 22 thru 24						
26	IOU/Muni	**Total Utility-Controlled Physical Resources**	Sum 16 + 21 + 25						
		EXISTING & PLANNED CONTRACTUAL RESOURCES							
		DWR Contracts:							
27	IOU	Contract A							
28	IOU	….							
29	IOU	Contract N							
30	IOU	Total DWR Contracts	Sum 27 thru 29						
		QF Contracts by fuel types:							
31	IOU, LADWP	Natural gas							
32	IOU, LADWP	Biofuels							
33	IOU, LADWP	Geothermal							
34	IOU, LADWP	Small Hydro							
35	IOU, LADWP	Solar							
36	IOU, LADWP	Wind							
37	IOU, LADWP	Other							
38	IOU, LADWP	Total QF Dependable Capacity	Sum 31 thru 37						
		Existing & Planned Renewable Contracts:							
39	All	Contract A							
40	All	….							
41	All	Contract N							
42	All	Total Existing & Planned Renewable Contracts	Sum 39 thru 41						

Electricity Resource Planning Form S-1: Dependable Capacity Resource Accounting Table (CRATs) (page 3 of 3)									
	Applies To:	**Other Bilateral Contracts:**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
43	All	Contract A							
44	All	….							
45	All	Contract N							
46	All	Total Other Bilateral Contracts	Sum 43 thru 45						
		Short Term and Spot Market Purchases:							
47	All	Short Term and Spot Market Purchases							
48	All	**TOTAL: EXISTING & PLANNED CAPACITY**	= 26+30+38+42+46+47						
49	IOU/Muni	Existing Interruptible / Emergency (I/E) Programs							
50	IOU	Uncommitted Dispatchable Demand Response							
51	All	**TOTAL CAPACITY + I/E and UDDR**	48 - (49 + 50)						
		FUTURE GENERIC RESOURCE NEEDS							
52	All	Generic Renewable Resources							
		Non-Renewable Generic Resources:							
53	All	Capacity for Baseload Energy							
54	All	Capacity for Load-following and Peaking Energy							
55	All	Load-Following (year-round) Capacity							
56	All	Peaking (seasonal) Capacity							
57	All	Total Capacity of Non-Renewable Generic Resources	Sum 53 thru 56						
58	All	Total Capacity of Future Generic Resources	Sum 52 + 57						

Supply Form S-2: Summary of Energy Resources (GWh)

LSEs are asked to estimate how much energy (in GWh) is needed to serve forecast needs and how much energy will come from various electricity supply resources. These estimates are required for all months of the forecast period, January 2006 through December 2016. LSEs are requested to provide this data on Supply Form S-2, Summary of Energy Resources, also called an energy balance table. The data submitted on Form S-2 should correspond one-to-one with the data submitted on the CRATs tables, Form S-1.

The instructions for individual lines on Form S-2 often repeat those provided for lines on Form S-1. This repetition is meant to provide clarity and convenience for people who will be completing these forms. The data categories on the two forms differ slightly, with 58 numbered lines on the CRATs table, and 53 numbered lines on the energy balance table. On Form S-2, it is not necessary for LSEs to estimate amounts of energy saved by price-sensitive demand response, interruptible programs, emergency programs, or uncommitted demand response programs. Also, there are no resource adequacy requirements, no 15% planning reserve margin, that LSEs need to include on their 10-year energy plan.

Energy Demand Calculations (GWh)

Line 1 Forecast Total Energy Demand

On line 1, all LSEs are asked to estimate total monthly energy consumption for all retail customers. Total energy demand includes transmission losses, distribution losses, energy needed to serve station loads of utility-controlled resources, and unaccounted for energy (UFE).

Line 2 ESP Energy Demand: Existing Contracts

On line 2, Energy Service Providers (ESPs) are asked to estimate total monthly energy needs of their existing customers. Energy totals on line 2 should only include obligations for current contract service periods.

Line 3 ESP Energy Demand: New & Renewed Contracts

On line 3, ESPs are asked to estimate total monthly energy needs that arise from new customers, plus contract renewals and extensions to serve existing customers. This forecast should be the “most likely” case. Enter the amount of energy needed to serve new customers plus existing customers who are expected to renew or extend ESP service.

Line 4 Direct Access (-)

On line 4, IOUs are asked to estimate amounts of energy used by Direct Access (DA) customers who have already left bundled service. For the reference case in the 2005 *Energy Report* cycle, IOUs should assume that there is no additional migration between IOU and DA service. (In the narrative report on 10-year resource plans, IOUs are asked to evaluate a different scenario than the reference case. In that evaluation, IOUs are asked to assume that by December 2012, 75% of all existing IOU customers with peak demand of 500 kW or more will depart for DA. Also assumed for that evaluation is that 30% of these customers leave in 2009, and another 15% depart in 2010, in 2011, and in 2012.)

LADWP, SMUD, and IID are asked to estimate amounts of energy used by DA customers who have left or will leave bundled service.

Line 5 Community Choice Aggregation and Departing Municipal Load (-)

IOUs are asked to identify a particular amount of Community Choice Aggregation (CCA) and Departing Municipal Load (DML) from a specified range of possibilities. As likely CCA/DML values are both very uncertain and apt to be utility-specific, each IOU is asked to choose a CCA/DML level for its reference case that meets the following requirements. The IOU should assume that departure begins no earlier than 2007 and not later than 2013. Total departure over this period should be at least 4% of bundled customer load and no greater than 10%. Enter these amounts of departing load on line 5.

Municipal utilities are asked to incorporate their assumptions regarding increased loads that may depart from IOU service into their total peak load estimates (line 1).

Line 6 Uncommitted Energy Efficiency (2009-2016) (-)

On line 6, IOUs are asked to estimate amounts of energy savings that could reasonably be expected from future energy efficiency programs. Assume that these programs are funded, implemented, and effective at targeted levels on schedule. Energy savings from currently uncommitted programs should begin showing up by January 2009 on line 6.

Line 7 Distributed Generation (-)

On line 7, IOUs are asked to estimate how much energy will be produced by DG and consumed by DG owners on the customer side of the meter. This number should represent new amounts of self-generation that would be subtracted from future IOU load obligations. The CPUC has not established a target for customer-side DG. This number does not include the supply of DG-produced energy that will be injected into the grid for use by IOU customers. That supply, if it is meaningful, should be listed elsewhere under existing and planned contractual resources.

Line 8 Net Energy Demand for Bundled Customers

Line 8 asks for the net energy demand for bundled customers. From the forecast energy demand on line 1, IOUs will subtract numerically positive amounts shown on lines 4, 5, 6, and 7.

POUs are asked to take the amount on line 1 and subtract the amount (if any) on line 4. For POUs and ESPs, if there no amounts are shown on lines 4-8, enter on line 9 the same amount shown on line 1.

Line 9 Firm Sales Obligations
On line 9, list total amounts of firm energy that the utility has contracted to deliver to other parties, both within the LSE's control area and beyond. If this capacity obligation is measured at some distant delivery point, add an appropriate amount to accommodate line losses and station load. If sales obligations include reserves, be sure to add 15% to the total sale obligations.

Line 10 Total Energy Requirement
Add line 8 to line 9 to calculate what is here called the total energy requirement. Enter this amount on line 10.

Existing and Planned Resources

Utility-Controlled Fossil and Nuclear Resources

This section asks for forecast data on fossil and nuclear resources owned or controlled by the reporting LSE. Beginning on line 13, submit one row of forecast energy production for each fossil plant. From this point forward on Form S-2, the line numbers on LSE submittals will not match those shown on the draft forms and instructions. Line 11 begins the listing of individual fossil and nuclear resources. Line 12 shows an ellipse representing one row for other plants in the series, and line 13 is for the last plant in the series, "Unit N." If the LSE controls a large number of resources in this section, it may be preferable to list them on a separate tab in Excel and list the totals only on line 14.

Line 11 Unit 1 [List each fossil and nuclear resource.]
Line 12 …..
Line 13 Unit N

Line 14 Total Fossil and Nuclear Energy Supply
On line 14, enter the sum of lines 11 through 13 (or an many lines as are needed to list each and every utility-controlled fossil and nuclear generating facility).

Utility-Controlled Hydroelectric Resources (1-in-2)

Unlike the section on fossil and nuclear plants above, LSEs are not being asked to report energy and capacity estimates for individual hydroelectric generating plants that they own or control.

Lines 15 and 17 on the S-2 energy balance table ask for total monthly hydroelectric energy production from all resources under LSE ownership or control. Energy production estimates should use median (1-in-2) hydrological conditions, with one notable exception, Hoover Dam, because USBR publishes highly reliable forecasts of capacity and energy for the lower Colorado River looking forward 24 months.

Therefore, LSEs with Hoover entitlements should use the latest USBR forecast for 2006, and then use 1-in-2 estimates for 2007 and beyond.

During the 2006-2016 forecast period, FERC licenses will expire for about 5,000 MW (Nameplate) of existing hydroelectric resources. LSEs are instructed to identify appropriate reductions in energy that are considered most probable. The most probable outcomes for hydro relicensing must consider eventual settlement negotiations, new FERC license conditions, and mandatory conditions set by SWRCB for water quality certification according to section 404 of the federal Clean Water Act. Forecast capacity or energy reductions as a result of relicensing could easily be in the range of 4% to 13%.

Line 15 Total for all plants over 30 MW nameplate

On line 15, estimate total hydroelectric energy production from all LSE owned or controlled hydro resources over 30 MW nameplate. This distinction follows FERC definitions of large and small hydro. Thirty MW is also the upper plant size limit that is eligible to be counted as a producer of "renewable energy" under California's RPS.

Line 16 Total for all plants 30 MW nameplate or less

On line 16, estimate total hydroelectric energy production from all LSE owned or controlled hydro resources equal to or less than 30 MW nameplate.

Line 17 Hydro Derate for 1-in-5 conditions (-)

On line 17, estimate how much less energy is produced during a "dry year" than during a median year. "Dry year" is defined as 1-in-5 hydrological conditions that have an 80% chance of being exceeded each and every year. If historical data is used as a proxy, LSEs should use generation numbers that were exceeded in 4 of the last 5 years, or 16 of the last 20 years. If feasible, use historical production data adjusted to current operating constraints and license conditions. If those conditions are expected to change during the forecast period, 2006-2016, adjust the averages accordingly so that this number represents what might be expected during a 1-in-5 dry year. Do not derate amounts of energy from Hoover Dam that derive from a published 24-month forecast by the U.S. Bureau of Reclamation (USBR).

Line 18 Hydro Derate for 1-in-10 conditions (-)

LSEs are also asked to provide a hydro derate number (stated positively) that represents 1-in-10 dry year conditions. Estimate how much less energy is produced during a "critically dry" year (1-in-10) than during a median year. This estimate is for comparative interest and system-wide risk assessment. Do not derate amounts of energy from Hoover Dam that derive from a published 24-month forecast by USBR.

Line 19 Total Hydro Energy Supply

To determine the amount on line 19, add lines 15 and 16 together, and subtract line 17. This amount is the total dependable "dry year" energy supply from hydroelectric resources under LSE control.

Existing and Planned Renewable Energy

This section asks for forecast data on individual renewable resources (other than hydro) that are under LSE ownership or control. These resources include existing resources as well as specific, named generating facilities that have been announced. List each generating resource on a separate row, similar to the section above on utility-controlled fossil fuel resources. If an LSE has a large number of renewable resources that it owns or dispatches, these may be listed on a separate tab with the total number brought forward to Form S-2, line 23.

Line 20 Unit 1 (fuel) [List each non-hydro resource.]
Line 21 …
Line 22 Unit N (fuel)

Line 23 Total Renewable Energy Supply

Line 24 Total Utility-Controlled Physical Resources
Take total amounts of forecast energy production listed in the three sections above for utility-controlled physical resources. These totals include fossil fuel and nuclear resources (line 14), utility-controlled hydro (line 19), and other renewable resources (line 23). Enter the sum of these three numbers on line 24.

Existing and Planned Contractual Resources

List the total forecast energy production by month for each LSE contract resource that will be available or which is planned to become available from specific contracts. Do not include Utility Distribution Company wheeling deliveries, such as direct access supplies to Stanford University within PG&E distribution territory.

DWR Contracts

The state's three major IOUs are asked to report energy supplies from specific DWR contracts. To *avoid the potential for double counting*, do not report these contract amounts elsewhere on the forms. List each contract on a separate row, starting with line 25. Actual line numbers for each IOU will vary from the line numbers in these instructions and on the form templates.

Line 25 Contract A
Line 26 ….
Line 27 Contract N

Line 28 Total Energy Supply from DWR Contracts
On line 28, enter the sum of forecast energy from all DWR contracts.

QF Energy Summary by Technology Type

Provide estimates of total monthly energy production through 2016 based on recorded or assumed performance of QF contract resources. Energy amounts should be summarized by the types of project in the LSE's portfolio. Do not list energy amounts for individual QF resources. Energy for sale to the LSE includes all forecast energy from firm capacity and from as-available capacity under contract for sale to the LSE.

Beginning on line 29, provide total amounts of energy from QFs as defined by PURPA, summarized by technology type. The section on QF contract resources does not ask LSEs for data about individual generating resources.

It is possible that existing QF renewable resources could be resigned for new QF contracts terms under PURPA auspices, or become committed under procurement proceedings for renewable resources. Therefore, the same existing QF renewable resources could be listed on lines 29-34 for the early years of the forecast period, and be listed again on lines 37-40 for the later years.

The IOUs and LADWP are asked to indicate the amounts of energy expected from QFs through 2016. During this forecast time period, most QF contracts will expire. LSEs need not assume that existing QF contracts will be renewed or extended beyond those for which an extension has already been mandated. PG&E and SCE shall provide a narrative scenario in which all of its QFs remain as providers of must-take energy over the forecast horizon.[7] That narrative should be included in the discussion of "Major Uncertainties and Risk Analysis" section of IOU reports on their 10-year plans.

Line 29 Natural gas

Line 29 asks for total capacity of all QF resources powered by natural gas.

Line 30 Biofuels

Line 30 asks for QF resources powered by biofuels, a large generic term including landfill gas, dairy waste, forest products, almond shells, and discarded fast food cooking oils.

Line 31 Geothermal

Line 31 is for all types of geothermal production including dry vapor and dual-flash systems.

Line 32 Small Hydro

Line 32 asks for small hydro QF totals, meaning only those plants rated 30 MW nameplate or less.

[7] SDG&E is not asked to provide this assessment because of the small amount of capacity involved in its expiring QF contracts.

Line 33 Solar

Line 33 takes in all types of solar resources, including photovoltaic and gas-assisted central station plants.

Line 34 Wind

Line 34 asks for a summary of existing and planned wind QF resources that the LSE knows or expects will be under contract. New wind resources are not expected to have new QF contracts, and should probably be listed elsewhere on the form.

Line 35 Other

Line 35 includes all other QF contract generating resources.

Line 36 Total Energy Supply from QF Contracts

On line 36, enter the arithmetic sum of all QF resources listed on lines 29 through 35.

Existing & Planned Renewable Contracts

LSEs are asked to list forecast energy supplies from renewable resources that are acquired to meet renewable energy procurement targets. This section is mandatory for the three major IOUs, and may also be relevant for other LSEs such as LADWP and SMUD whose governing boards have adopted specific renewable energy goals. Each contract should be named and listed on a separate row beginning with line 37. Energy from individual generating facilities, such as wind turbines, is not being requested in this section. To avoid double counting, do not repeat a listing of contract resources if they are already included in earlier sections on utility-controlled hydro resources or QF contract resources. If an LSE has or projects a large number of renewable contracts, they may be listed on a separate spread sheet, equal to lines 37 to 39.

Line 37 Contract A
Line 38 ….
Line 39 Contract N

Line 40 Total Existing & Planned Renewable Contracts

On line 40, enter total energy amounts from all renewable contract resources, here represented as lines 37 through 39.

Other Bilateral Contracts

All LSEs are asked to list forecast energy supplies from other bilateral contracts that are not already counted in earlier sections on utility-controlled hydro, DWR contracts, QF contracts, and renewable resource contracts. Each bilateral contract should be named and listed on a separate row beginning with line 41. Energy output from individual generating facilities is not being requested in this section. To avoid double counting, do not repeat a listing of contract resources if they are already included in earlier sections. If an LSE has or projects a large number of other bilateral contracts, they may be listed on a separate spread sheet, equal to lines 41 to 43.

Line 41 Contract A
Line 42 ….
Line 43 Contract N

Line 44 Total Energy Supply from Other Bilateral Contracts
On line 44, enter total energy amounts from all other bilateral contracts, here represented as lines 41 through 43.

Short Term and Spot Market Purchases

Line 45 Short Term and Spot Market Purchases
All LSEs are asked to forecast how much of their monthly energy needs will be met by short term purchases and by spot market purchases. List these amounts, if any, on line 45 or enter zero. In theory, if dependable capacity conventions and resource adequacy requirements are appropriate and prudent, very few LSEs will have a planned need to purchase energy in short-term, day ahead, and hour-ahead markets. In practice, however, LSEs recognize that significant amounts of energy can be purchased in spot markets when at less cost than generation from utility-controlled resources. Short term and spot market purchases are defined here to include all procurement that is less than three consecutive months in duration.

Line 46 Total: Existing and Planned Energy
On line 46, enter the sum of existing and planned electricity supply resources that were counted in earlier sections. The amount to enter on line 46 is the sum of lines 24 (utility-controlled resources), 28 (DWR contracts), 36 (QF contracts), 40 (renewables contracts), 44 (other bilateral contracts), and 45 (short term and spot market purchases).

Future Generic Resource Needs

Lines 47 through 53 are for non-specific "generic" resources that will be needed to meet forecast load obligations. Most, if not all, LSEs will need to procure additional resources during the next ten years.

In some instances, LSEs have committed to specific but yet-to-be-built physical resources. All announced projects with names and locations should be listed in earlier sections on utility-controlled resources (lines 11 to 24), or contract resources (lines 25 to 44).

Many LSEs have not yet begun to consider specific projects to serve loads after 2010, or if these loads could be better served with physical or contractual resources. During a 10-year planning horizon, many supply and demand uncertainties are compounded, which makes peak load forecasts and financial investment decisions highly contingent or tentative at best. Nonetheless, the daily and seasonal shapes of LSE load obligations may be reasonably estimated, and each LSE knows its own portfolio of existing and planned resources, and how that portfolio matches up with forecast loads. For projected load and necessary reserves that are *not* covered by existing and planned resources, all LSEs are expected to provide estimates of what would be needed generically to meet the LSE's obligations. The first such generic resource to be identified is that needed to meet renewable energy retail sales targets (especially the IOUs). After that, all LSEs are asked to identify generic baseload, shaping, and/or peaking resources that will be needed through 2016, and the extent to which generic shaping and peaking resources are needed seasonally or year-round. The energy outputs from these generic new supply sources should be specified by resource type on line 48 through line 53.

The listings of generic resources on form S-2 must be consistent with those listed on form S-1. Most LSEs have a generic forecast need for certain types of capacity, which will be shown on form S-1. Form S-2 asks for the expected energy production from those same generic resources. There is no planning reserve requirement for energy. As stated in the instructions for form S-1, LSEs are asked to indicate what type of generic resource would be expected to meet a reserve requirement and energy needs most cost-effectively, even though the forward procurement of such a resource is not presently planned.

Generic Renewable Resources

Line 47 Generic Renewable Energy

On line 47, enter the aggregate amounts of energy expected from renewable resources beyond those specific, named resources that already exist or which are already listed in earlier sections as planned contractual or utility-controlled renewable resources.

For IOUs, LADWP, and SMUD, this value will be influenced by the RPS that they are asked to assume. For the reference case in the 2005 *Energy Report* cycle, IOUs are asked to assume that in calendar year 2010, 20% of all retail energy sales will have been matched by energy produced from state-defined eligible renewable resources. To ramp up and maintain this 20% renewable energy target (ignoring contributions of large hydro), IOUs may assume that eligible hydro resources are generating under median (1-in-2) hydro conditions. However, IOUs may not assume that three-year averaging rules or tradable renewable energy credits (RECs) will be employed to meet these assumed targets.

The values entered on line 47 shall be consistent with the entries submitted on Form S-3, generic renewable capacity and energy locations. On Form S-3, the IOUs are asked to provide resource plans which enable them to meet a renewable energy target of twenty percent of retail sales by 2010 and maintain purchases at 20% renewables through 2016. They are asked to provide their best projections of the energy and associated capacity that will meet these targets by location (ISO zone, control area) and technology (geothermal, biofuels, wind, solar). The IOUs will be filing 10-year renewables plans at the CPUC and the two filings should be compatible. For the Accelerated Renewables Scenario, IOUs, LADWP, and SMUD are also asked to develop a second set of generic renewable energy supply numbers (for lines 47 forward on form S-2), using higher targets for years 2010 through 2016 to be filed April 1, 2005. (see Accelerated Renewables Scenario as described in the 10-year Resource Plan section) In order to assess the implications of recommendations in the *2004 Integrated Energy Policy Update* on accelerating renewables, PG&E, SDG&E, LADWP, and SMUD are asked to provide an alternative case that assumes that by 2016, 28% of annual retail energy sales totals will be matched by eligible renewable energy produced by physical and contractual resources in the IOU's portfolio. SCE is asked to provide and assess a scenario that has 31 percent of retail sales served by eligible renewable energy by 2016. The effect of achieving higher targets by 2016 shall be shown with steady incremental changes above the 20% target for 2010. Again, linear progress towards achievement of the 2016 target may assume median hydrological conditions each and every year, but may not assume the use of RECs or three-year averaging.

The obligation to acquire renewable resources varies considerably among different classes of LSEs (IOUs, municipal utilities, ESPs and CCAs). The nature of this obligation is likely to change considerably over time in numerous ways that are difficult to forecast with any probabilities. LSEs are directed to identify potential RPS scenarios that would strongly affect eligible renewable procurement, and to discuss these effects on Planned Resources in the narrative sections of their response.

Generic Non-Renewable Resources

Line 48 Generic Baseload Energy

On line 48, enter the energy associated with baseload capacity needs that are not met by existing resources, planned resources, or generic renewable resources. Values which are sustained year-round over a long period reflect needs for which the LSE might consider construction, purchase, or a long-term power purchase agreement (PPA) for the output of a baseload resource. Values which are sustained for shorter periods reflect baseload needs for which the LSE might consider a shorter-term energy contract (e.g., all energy, for 7 days x 24 hours).

Line 49 Generic Load-following and Peaking Energy

On line 49, enter the cyclical energy needs that will not be met by existing resources, planned resources, or generic renewable resources.

Line 50 Generic Load-Following (year-round) Energy

On line 50, enter the energy associated with year-round load-following needs that will not be met by existing resources, or planned resources, or generic renewable resources. This estimate is for the energy needed to meet predictable daily load swings that can or do occur throughout the year.

Line 51 Generic Peaking (seasonal) Energy

On line 51, enter the energy associated with contractual or demand-side resources needed to meet peak energy needs on a strictly seasonal basis.

Line 52 Total Non-Renewable Generic Energy Needs

On line 52, enter the sum of lines 48, 49, 50, plus 51.

Line 53 Total Future Generic Resource Needs

On line 53, enter the sum of lines 47 and 52.

Electricity Resource Planning Form S-2

Energy Balance Resource Accounting Table (page 1 of 3)

California Energy Commission

Filing LSE:

Date:

Contact Name:

Contact Number:

	Applies To:	**ENERGY DEMAND CALCULATIONS (GWh)**	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
1	All	Forecast Total Energy Demand							
2	ESP	Energy Demand: Existing Contracts							
3	ESP	Energy Demand: New & Renewed Contracts							
4	IOU	Direct Access (-)							
5	IOU	CCA & Departing Municipal Load (-)							
6	IOU	Uncommitted Energy Efficiency (2009-2016) (-)							
7	IOU	Distributed Generation (-)							
8	All	Net Energy Demand for Bundled Customers	1 - (sum 4 thru 7)						
9	IOU/Muni	Firm Sales Obligations							
10	All	Total Energy Requirement	Sum 8 + 9						
		EXISTING & PLANNED RESOURCES							
		Utility-Controlled Fossil and Nuclear Resources:							
11	IOU/Muni	Unit 1 [List each fossil and nuclear resource.]							
12	IOU/Muni	…..							
13	IOU/Muni	Unit N							
14	IOU/Muni	Total Fossil and Nuclear Energy Supply	Sum 11 thru 13						
		Utility-Controlled Hydroelectric Resources (1-in-2):							
15	IOU/Muni	Total for all plants over 30 MW nameplate							
16	IOU/Muni	Total for all plants 30 MW nameplate or less							
17	IOU/Muni	Hydro Derate (-) for 1-in-5 conditions							
18	IOU/Muni	Hydro Derate (-) for 1-in-10 conditions							
19	IOU/Muni	Total Hydro Energy Supply	Sum 15 + 16 -17						

Electricity Resource Planning Form S-2: Energy Balance Resource Accounting Table (page 2 of 3)

	Applies To:	Existing & Planned Renewable Energy:	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
20	IOU/Muni	Unit 1 (fuel) [List each non-hydro resource.]							
21	IOU/Muni	…							
22	IOU/Muni	Unit N (fuel)							
23	IOU/Muni	Total Renewable Energy Supply	Sum 20 thru 23						
24	IOU/Muni	**Total Utility-Controlled Physical Resources**	Sum 14 + 19 + 23						
		EXISTING & PLANNED CONTRACTUAL RESOURCES							
		DWR Contracts:							
25	IOU	Contract A							
26	IOU	….							
27	IOU	Contract N							
28	IOU	Total Energy Supply from DWR Contracts	Sum 25 thru 27						
		QF Contracts by fuel types:							
29	IOU, LADWP	Natural gas							
30	IOU, LADWP	Biofuels							
31	IOU, LADWP	Geothermal							
32	IOU, LADWP	Small Hydro							
33	IOU, LADWP	Solar							
34	IOU, LADWP	Wind							
35	IOU, LADWP	Other							
36	IOU, LADWP	Total Energy Supply from QF Contracts	Sum 29 thru 35						
		Existing & Planned Renewable Contracts:							
37	All	Contract A							
38	All	….							
39	All	Contract N							
40	All	Total Existing & Planned Renewable Contracts	Sum 37 thru 39						

Electricity Resource Planning Form S-2: Energy Balance Resource Accounting Table (page 3 of 3)

	Applies To:	Other Bilateral Contracts:	Sum of lines:	Jan-06	Feb-06	Mar-06	Apr-06	….	Dec-16
41	All	Contract A							
42	All	….							
43	All	Contract N							
44	All	Total Energy Supply from Other Bilateral Contracts	Sum 41 thru 43						
		Short Term and Spot Market Purchases:							
45	All	Short Term and Spot Market Purchases							
46	All	**TOTAL: EXISTING & PLANNED ENERGY**	= 24+28+36+40+44+45						
		FUTURE GENERIC RESOURCE NEEDS							
47	All	Generic Renewable Energy							
		Non-Renewable Generic Resources:							
48	All	Generic Baseload Energy							
49	All	Generic Load-following and Peaking Energy							
50	All	Generic Load-Following (year-round) Energy							
51	All	Generic Peaking (seasonal) Energy							
52	All	Total Non-Renewable Generic Energy Needs	Sum 48 thru 51						
53	All	Total Future Generic Resource Needs	Sum 47 + 52						

Supply Form S-3: Generic Renewable Capacity and Energy Locations

Several California LSEs have targets for increasing the amount of energy provided to customers that will be generated by new renewable sources. Existing sources of renewable generation are not adequate to meet these needs. To meet these targets, new generation, new transmission, or tradable renewable energy credits (RECs) will be needed, and perhaps some combination of all three. LSEs who have established specific annual targets for renewable energy procurement are asked to complete Form S-3. This includes all three major IOUs, LADWP, and SMUD. These LSEs are asked to use capacity and energy numbers already provided for Generic Renewable Resources and shown on line 51 of the CRATs table (Form S-1) and on line 47 of the Energy Balance table (Form S-2).

Generic Renewable Capacity (Projected MW)

Location

Using the generic renewable capacity numbers shown on line 47 of the CRATs table, LSEs are asked to provide geographic and technology breakouts. First, it will be necessary to identify only the total annual energy and dependable capacity numbers from the monthly totals on S-1 and S-2. Secondly, LSEs are asked to allocate by location the total dependable capacity from new renewables on Form S-3. On the first page of this form list the total capacity expected to be developed in the following transmission areas: Local, NP15, SP15, Imperial Valley, and Other (specify). Local is defined as utility-controlled distribution wires that do not require use of wholesale bulk transmission lines (generally 100 kV lines and up). Capacity numbers will almost certainly increase incrementally over time as new renewable generation is developed and brought online.

Fuel Type

LSEs are asked to allocate annual generic renewable energy totals according to the major sources of potential supply: biofuels, geothermal, small hydro, solar, wind, and other. LSEs may breakout the category of other supplies to identify specific technology or fuel types considered significant and likely in the 10-year resource plan. Listing projected types of generic renewable resources is not a commitment or obligation to do so. This information is essential, however, as an input to transmission corridor planning given the difficulties of that process.

Generic Renewable Energy (Projected GWh)

Location

IOUs, LADWP, SMUD, and all other LSEs with Renewable Portfolio Standards (RPS) are asked to perform the same calculations for new generic renewable energy supplies using energy projections instead of dependable capacity. On the second page of Form S-3 list the total annual amounts of energy projected to come from the listed transmission areas: Local, NP15, SP15, Imperial Valley, and Other (specify). These annual energy totals should equal the amounts of monthly generic renewable energy supplies shown on line 47 of Form S-2, the Energy Balance table, or each scenario, respectively.

Fuel Type

IOUs, LADWP, SMUD, and other LSEs with RPS goals are asked to allocate projected annual generic renewable energy totals according to the major technological sources of potential supply: biofuels, geothermal, small hydro, solar, wind, other. Again, these annual energy totals should equal the amounts of monthly generic renewable energy supplies shown on line 47 of Form S-2, the Energy Balance table for each scenario.

Electricity Resource Planning Form S-3

Generic Renewable Capacity and Energy Locations

California Energy Commission

Filing LSE:

Date:

Contact Name:

Contact Number

GENERIC RENEWABLE CAPACITY (Projected MW):

LOCATION	FUEL TYPE	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Local	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
NP15	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
SP15	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
Imperial Valley	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
Other (specify)	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
TOTAL MW (sum of above):												

Electricity Resource Planning Form S-3: Generic Renewable Capacity and Energy Locations (page 2 of 2)												
GENERIC RENEWABLE ENERGY (Projected GWh):												
LOCATION	FUEL TYPE	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Local	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
NP15	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
SP15	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
Imperial Valley	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
Other (specify)	Biofuels											
"	Geothermal											
"	Small Hydro											
"	Solar											
"	Wind											
"	Other											
TOTAL GWh (sum of above):												

Supply Form S-4: QF Energy and Cost Projections

LSEs are asked to provide forecast generation data on QF resources so that Energy Commission staff will be better able to address the following questions:

- What are the resource adequacy impacts of expiring QF contracts? What share of this impact arises from the expiration of the handful of largest contracts?
- What are the implications of expiring QF contracts for energy and capacity costs under different assumptions regarding replacement costs?
- How do various QF contracts affect the net short/long energy position and address reliability concerns?
- What are the potential impacts of expiring contracts on the incremental need to procure renewable energy?
- What contribution do QF contracts make to natural gas price risk faced by California ratepayers?

LSEs are asked to provide estimated annual capacity, generation, and cost estimates for individual QF contracts for 2006 -2016. Each LSE that purchases energy from Qualifying Facilities (QFs) is required to submit projections regarding the annual energy to be purchased under each contract along with the cost of these purchases. Contracts with available capacity of less than 10 MW can be aggregated by fuel type (biomass, cogeneration, geothermal, small hydro, solar[8] and wind). Once the under-10 MW QF contracts have been aggregated by technology, a secondary breakout is requested for pricing mechanisms. For example, for gas-fired cogen QF resources under contract to an IOU might have subgroups for those contracts that are indexed to gas prices at Malin, and those that are indexed to gas prices at Topoc.

Specific types of information requested from LSEs are described below. These information categories correspond to those shown on Form S-4, Projected QF Energy and Costs. For convenient display and printing, only the first two years are shown on the template, 2006 and 2007. Filers are asked to extend these columns to include all years through 2016.

QF Name

Enter the project name as listed in the most recent Qualifying Facilities Semi-Annual Status Report.

Contract ID

Enter the QFID as listed in the most recent Qualifying Facilities Semi -Annual Status Report.

Termination Date

Enter the expiration date of the contract.

---

[8] Contracts with facilities that use gas-assisted solar technologies may apportion energy and costs between the two fuels.

Dependable Capacity

Enter the dependable capacity for each contract, or for each technology group of under-10 MW contracts. As explained in the instructions for Form S-1, the Dependable Capacity total for QF resources includes everything that the LSE deems likely to be available during a specific month. Estimates of QF dependable capacity should be based on average historical generation during peak hours as defined in Standard Offer 1 contracts, which is Noon to 6 PM summer weekdays excluding holidays. Dependable Capacity includes both Firm Contract Capacity and that portion of As-Available Contract Capacity that the LSE deems likely to be available on any given peak hour, contracts notwithstanding, based on statistical performance history.

On Form S-4, line 24, the total dependable capacity for all QF resources should match the total on Form S-1, line 38. As also explained in the instructions for Form S-1, if dependable capacity is calculated in a different manner for any resource or class of resources, the methodology for estimating dependable capacity should be presented in a note to the table.

Contract Pricing

Enter the mechanism used to determine energy payments under the contract. This may be a fixed price (“Fixed”) or an indexed price. If an indexed price, describe insofar as necessary to distinguish the index used from other indexes that are used to determine energy payments to QFs (e.g., Malin, Topoc, or Citygate delivery points).

Contract Energy

Enter the total estimated energy purchases (GWh) under the contract(s) for the year indicated, 2006 through 2016.

Annual Energy (GWh)

Enter the total expected energy production in GWh under each contract for each year.

Annual Energy Costs

Enter the estimated energy payments under the contract for the year indicated. The number should represent total dollar costs for all energy purchases shown in the previous column. Indicate if real or nominal values. If real values are used, provide the base year. If nominal, provide the deflator series in notes appended to the form.

Annual Fixed Costs

Enter the estimated capacity payments and other fixed payments under the contract for the year indicated. The term “fixed costs” is meant to include all non-energy payments, such as ancillary services. Some “fixed cost” payments may be based on actual performance and thus are not truly “fixed” as immutable givens. Enter a dollar amount for the entire year based on expected performance for each QF contract. For aggregated contracts by fuel type, provide a total estimate of fixed costs that the LSE considers reasonable.

Electricity Resource Planning Form S-4

Projected QF Energy and Costs
California Energy Commission

Filing LSE:	
Date:	
Contact Name:	
Contact Number:	
Page Number:	

Contract Name	Contract ID	Termination Date	Dependable Capacity	Contract Pricing	Contract Energy	2006 Energy GWh	2006 Energy Costs	2006 Fixed Costs	2007 Energy GWh	2007 Energy Costs	2007 Fixed Costs
Contract A											
Contract ….											
Contract N											
Under 10 MW:											
Natural Gas											
Biofuels											
Geothermal											
Small Hydro											
Solar											
Wind											
Other											
Totals						0	$0	$0	0	$0	$0

Supply Form S-5: Bilateral Contracts

All large LSEs are asked to provide a few standard types of information regarding existing bilateral contracts that have been signed with suppliers of capacity and/or energy. This information is needed to assess the following characteristics of statewide supply and demand balances:

- Does the contract encumber in-state capacity or is it likely to do so?
- Does the contract encumber out-of-state capacity in service of California loads?
- Is the supplier in control of a physical resource or likely to be so?
- Under what circumstances, if any, may the energy or capacity associated with the contract be unavailable during peak hours?
- Under what set of resource adequacy requirements would the contract provide count as Qualifying Capacity, or not?

Information Format Requirements

LSEs are asked to submit the required information on Electricity Supply Form S-5: Bilateral Contracts. A sample template is provided in Excel format. Some of the information requested is categorical, and some is numeric, but several topics are primarily descriptive in nature. Information provided in Word or Acrobat files will be accepted provided that responses are complete and follow the prescribed sequence. A separate form will be needed for each bilateral contract.

Contracts Covered By This Request

For each and every bilateral contract that specifies supply of energy or capacity lasting at least three consecutive months, LSEs must provide the information described below and shown on Form S-5. There are three exceptions to this requirement:

- QF contracts
- DWR contracts
- Contracts between California IOUs and public utilities for the integration of hydro resources (e.g., a PG&E hydropower contract with Nevada Irrigation District).

Supplier

Name the contracted supplier/producer of energy and/or capacity according to the contract. This entity is sometimes called the counterparty to the contract.

Start Date

State the initial delivery date of the product(s) being purchased. If this is contingent upon future actions by parties to the contract, market conditions, or other future events, this should be explained in notes appended to the form.

Expiration Date

Provide the date for final delivery of the product(s) being purchased. If this date is contingent upon future actions by parties to the contract, market conditions, or other future events *prior to the contract's inception*, this should be explained in notes appended to the form. Information regarding the ability of one party to unilaterally terminate the contract after its inception should be entered under Performance Requirements and Termination/Extension Clauses and Rights or in notes appended to the form.

Contract Product(s)

Indicate the commodity and service products for which delivery is being contracted. Examples include but are not limited to energy, energy exchange, capacity, capacity with call option (and other market-contingent products), and ancillary services. If transmission will be provided by seller, specify typical paths. For each contract, specify which party will serve as scheduling coordinator.

Dependable Capacity (MW)

List the maximum dependable capacity (MW) available to the LSE during annual superpeak weekday hours (HE 13 through HE 17) in Q3. If the MW available varies across months of the year, days of the week, or hours of the day, this variation should be described under Availability in the next entry. If dependable capacity that will be available to the LSE is determined somewhere other than the busbar nearest a named generator, name that location.

Contract Pricing

For contracts for energy, indicate whether the contract is fixed-price, a tolling agreement (or otherwise pegged to a market fuel price), or an energy exchange. If it is an energy exchange agreement, describe the return requirements in the notes.

Availability

Indicate time periods during which product is available. Examples include:

7 x 16 (5,840 hours per year)
6 x 16 (Monday – Saturday, 6 AM – 10 PM, excluding NERC holidays)
Q3, 7 x 8, HE 13 – HE 20 (third quarter, 7 days a week, 1:00 PM to 8:00 PM)
Mos. 5-10, max 50 hrs/mo, (May – October, up to 50 hours per month)
100 MW off-peak (year-round, all hours not covered by 6 x 16)

Must-Take

If applicable, indicate must-take characteristics of the contract. Examples include:

Yes (for energy contract, all energy indicated jointly by MW and Availability)
Min 30,000 MWh monthly

Unit Contingent

If delivery is contingent upon the availability of a specific unit or units, indicate the unit(s). If the seller was assumed to have control of capacity and transmission rights, or if seller was or will be required to demonstrate such as a condition of the contract, please enter “contingent”. If seller may provide system power, enter “portfolio.” If seller was not and will not be required to demonstrate control of capacity and transmission rights as a condition of the contract, enter “No.”

Firm

Yes / No. “Yes” indicates that seller can only fail to provide replacement power under *force majeure* provisions in order to avoid involuntary load curtailments in another control area. “No” indicates non-delivery may occur for other reasons, such as market conditions or transmission congestion. Contracts without firm delivery requirements typically include provisions for liquidated damages.

Dispatchable

If this is a unit-contingent contract, indicate if the buyer has the right, or at least some rights, to dispatch the unit(s).

Delivery Points

Name the point(s) at which energy can be delivered (*e.g.*, NP15, Malin, Lugo substation). If multiple points, indicate whether buyer or seller has option.

Termination and Extension Rights

LSEs should indicate which party or parties have the right to unilaterally terminate or extend the contract (for reasons other than non-performance of the other party).

For termination rights, indicate the possible termination dates, notification requirements, and allowable circumstances. For example, “Seller may terminate on January 1st of each year beginning 1/1/2007 with 90 days prior notice.”

For extension rights, indicate the possible extension dates, length of extension, notification requirements, and allowable circumstances. For example, “From 7/1/2006 until 1/1/2008, buyer may extend contract for six months with 30 days prior notice, provided that energy purchases have exceeded 80,000 MWh in each of the three preceding calendar quarters.”

Performance Requirements

Indicate circumstances under which buyer can terminate contract for non-performance. For example, “Buyer may terminate contract for non-performance if wind energy delivered at the busbar fails to meet at least 80% of specified targets for each of three consecutive quarters. Thirty days notice is required.”

Notes

Include any clarifying or explanatory statements required or considered appropriate.

Electricity Resource Planning Form S-5

Bilateral Contracts
California Energy Commission

Filing LSE:	
Date:	
Contact:	
Contact Number:	
Page Number:	

Supplier	
Start Date	
Expiration Date	
Contract Product(s)	
Dependable Capacity (MW)	
Contract Pricing	
Availability	
Must Take	
Unit Contingent	
Firm	
Dispatchable	
Delivery Points	
Termination and Extension Rights	
Performance Requirements	
Notes	(1)
	(2)

Historical Hourly Generation Data Requests

The Energy Commission asks LSEs to report recent hourly generation data from three types of supplies in their portfolio: Qualifying Facilities, Wind, and Hydroelectric resources. No particular reporting template is provided for reporting this data. LSEs are asked to provide this hourly generation data in the electronic format they deem most appropriate, and the preference is for Excel files.

QF Energy Purchase Data

All LSEs that have contracts with Qualifying Facilities (QFs) are asked to provide data on historical purchases for calendar years 2003 and 2004. Energy Commission staff understands that all IOUs and LADWP have QF contracts, though there may be other LSEs in California who also have QF contracts. For each QF facility, enter the CA ISO zone for the point of interconnection of the facility (e.g., NP15, SP15, and ZP26). If interconnection is outside CA ISO, name the control area in which it is located (e.g., LADWP, SMUD, IID).

LSEs are asked to report amounts of energy that were actually supplied on an hourly basis for both years. Historical data on capacity, ancillary services, and prices are not required. LSEs are asked to provide hourly supply data for each QF resource that is 10 MW or larger, defined as the maximum capacity that may be available to the LSE (not counting station load and minimum auxiliary load). For individual QF contracts with available capacity of less than 10 MW, hourly generation values should be aggregated by technology.

Additional Wind Generation Data

Continued development of renewable energy resources points to an increasing use of wind turbines. This development is supported by state and utility renewable portfolio standards, by the state's Energy Action Plan, by CPUC directives to the IOUs, and by expressions of public desire. However, existing data are not sufficient to evaluate potential reliability impacts associated with a growing reliance on wind to meet the state's energy needs. Nor is data available to evaluate disparate claims regarding likely performance and capacity values of wind facilities that are now being brought on line or that are now undergoing retrofits. Currently, the Energy Commission receives a limited amount of such data on a voluntary basis from those owners who agree to provide the information.

The Energy Commission asks large LSEs to submit hourly wind generation data for calendar years 2003 and 2004. LSEs that served peak loads of less than 200 MW in both 2003 and 2004 may ask to be exempt from this data request. A substantial share of the wind generation in California is provided to IOUs under QF contracts. Data on historical and forecast QF generation has been requested in earlier sections. Where wind projects are owned by LSEs, or where wind energy is purchased by LSEs under non-QF contracts involving projects of 10 MW (nameplate) or more, the Energy Commission asks that these LSEs provide the requested hourly purchase data.

The Energy Commission also requests that merchant wind generators larger than 10 MW (nameplate) report their hourly injections onto the transmission grid during calendar years 2003 and 2004.

Selected Hourly Hydroelectric Generation Data

The Energy Commission lacks sufficient data to assess the system-wide availability of hydro generation and capacity during peak hours in the summer, as well as to assess the role that individual generation facilities play in meeting peak loads. This information is needed to evaluate whether California has sufficient generation capacity to reliably meet the demand for energy, and the capacity value of individual facilities relative to their environmental impact.[9]

The Energy Commission requests historical hourly hydro generation data from selected hydro asset owners in order to evaluate hydro availability during peak hours and under a range of hydrology conditions. CA ISO has already provided hourly data on the performance of many of the state's hydro facilities.[10] These hydro facilities include those of the IOUs, along with most of the hydro resources in the CA ISO control area that are operated by publicly owned utilities, irrigation districts, and water agencies. The remaining needed data primarily relates to those hydro facilities operated by public utilities outside the CA ISO control area, and includes the following operators:

- Hetch Hetchy Water and Power / City and County of San Francisco PUC
- Imperial Irrigation District (IID)
- Los Angeles Department of Water and Power (LADWP)
- Metropolitan Water District (MWD)
- Sacramento Municipal Utility District (SMUD)
- Turlock Irrigation District (TID)
- U.S. Bureau of Reclamation (USBR)

The Energy Commission requests historical data for 1998 through and including 2004. These data need to be disaggregated by facility, and should include values for pump storage facilities.

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[9] The Energy Commission is requesting this data for use in preparing the Environmental Performance Report.
[10] The Energy Commission obtains this data pursuant to SB 1305, and it is subject to confidentiality restrictions.

Ten-Year Resource Plans

This section of the forms and instructions provides the Energy Commission staff proposal for additional information relating to key scenarios and uncertainties that LSEs will be required to file by April 1, 2005. As discussed above, the *Energy Report* Committee plans to hold an additional workshop on February 15, 2005 to review this proposal for additional information. Following that workshop, the Committee will issue an order that directs the relevant parties to file that additional information by April 1, 2005, including additional direction or revisions and errata to these forms and instructions that are necessary. The Committee's Order will be brought back to the Energy Commission for adoption.

Reference Cases, Costs, and Scenarios

All LSEs that served peak retail loads of 200 MW or more in either 2003 or 2004 are asked to submit a 10-year electricity supply plan. The Capacity Resource Accounting Table (Form S-1) and the Energy Balance table (Form S-2) are essential components of this 10-year plan. The Energy Commission asks each LSE to prepare a "reference case" which includes the numbers on Form S-1 and S-2. This reference case is a resource plan that "assumes away" numerous uncertainties. For example, in the reference case, IOUs are asked to assume that Direct Access (DA) load that they no longer serve will continue to be served by other providers, and that no current bundled customers take DA service.

This reference case narrative should include assessments of the major uncertainties which influence resource planning decisions, along with some discussion of their actual influence on the reference case resource plan.

The IOUs are asked to submit their preferred resource plan in addition to the reference case. The preferred resource plan includes a narrative section discussed herein, and a full set of electricity supply forms (S-1 through S-5) that incorporate the preferences, assessments, strategies, and judgments of the IOU. For example, the instructions for the reference case ask IOUs in include certain assumptions about departing load, energy efficiency, and renewable energy procurement. If an IOU prefers to use a different target (or a different range of numbers) in its resource plan, then those metrics should be explained in the narrative of the preferred resource plan. The preferred numbers should be used on a second set of forms.

All municipal utilities are requested to submit the most recent annual report to their customers pursuant to Public Utilities Code Section 387(b).

Resource Plan Costs

The Energy Commission asks IOUs to provide estimates of the annual costs of meeting load obligations for the reference case resource plan. This should be the "all-in" generation cost, plus the transmission and delivery cost. These costs should include but are not necessarily limited to the variable costs of operating utility-owned generation, contract costs, and the net revenue from activity in wholesale markets. If an IOU is submitting a preferred resource plan along with a reference case, then the IOU is asked to provide annual cost estimates of the preferred resource plan as well as the reference case.

For all LSEs, any additional, significant and quantifiable costs which facilitate comparisons between the reference case resource plan and additional scenarios should also be presented. Significant costs whose determination is beyond the scope of analysis requested should be discussed.

In providing their projections for both the reference case and the accelerated renewables scenario, the IOUs, LADWP and SMUD should describe the potential cost (direct costs, additional transmission, etc.) to ratepayers of meeting these RPS goals. These LSEs are also asked to describe barriers which are limiting their ability to implement RPS policies, including barriers to achieving specific RPS targets. These LSEs are asked to explain what might be done to reduce, overcome, or better assess each such barrier. IOUs are asked to discuss how procurement of additional intermittent resources could affect or impact the remainder of its portfolio.

Accelerated Renewables Scenario

In its 2004 *Energy Report* update, the California Energy Commission adopted the following recommendations for achieving ambitious renewable energy goals:

> The state should enact legislation to require all retail suppliers of electricity, including large publicly-owned electric utilities, to meet the accelerated 20 percent eligible renewable goal by 2010 and a longer-term goal of 33 percent by 2020, using common definitions of eligible renewable energy. In addition, the state should enact legislation that allows the CPUC to require Southern California Edison (SCE) to purchase at least one percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010, 30 percent by 2015 and 35 percent by 2020.

In order to assess the implications of the recommendations for this new legislation, PG& E , SDG&E and the two largest publicly-owned electric utilities (LADWP, and SMUD) should provide an alternate case that has 28 percent of retail sales served by eligible renewable energy[11] by 2016 (28% is the 2016 value for the 33% by 2020 target). Southern California Edison is asked to provide and assess a scenario that has 31 percent of retail sales served by eligible renewable energy by 2016.

All the LSEs named above are expected to provide a plausible projection of the technologies and locations (using forms S-1, S-2 and S-3) for generic renewable resources that would be needed to meet the requirements in this scenario.

[11] Public Utilities Code Section 399.12 (a)(1-4).

Local Reliability Areas Scenario

The IOUs are asked to present a scenario in which they procure sufficient resources in the ISO's Local Reliability Areas to meet local deliverability requirements. While these requirements have yet to be determined, a reasonable starting point would be to assume that in 2006 the IOUs would contract with those resources under RMR contract in 2005 and would continue to do so until and unless (a) transmission upgrades reduce the need for capacity and generation, or (b) the utility constructs new capacity in the LRA or enters into a long-term PPA with same.

This scenario requires that the IOUs make projections regarding the construction of new capacity in local reliability areas in their service territory. The incentive for IOUs to build or contract with such capacity depends in part upon the expected costs of contracts with existing resources; the annual fixed revenue requirements as stated in the 2005 RMR contracts should be used to inform those estimates.

The IOUs are also asked to discuss the transmission implications of this requirement, *i.e.*, the impact of these local reliability procurement constraints on the costs of meeting load obligations may not only encourage the construction of new facilities, but transmission upgrades which eliminate or reduce the need for capacity within the LRA. In short, the IOUs are asked to compare the cost of contracting with existing resources, building a new resource in the LRA, and increasing the transfer capability into the LRA.

Topics of Special Concern

Potential Impact of a GHG Adder on Bid Evaluations

The CPUC decision (D.04-12-048) of December 21, 2004 in R.04-04-003 requires that the IOUs apply a greenhouse gas (GHG) adder to bids received in response to future solicitations for energy and capacity, as well as to consider GHG emissions in their long-term planning process. The value of the GHG adder is to be determined in R.04-04-025 in March 2005.

IOUs are asked to submit a discussion of the potential obstacles, benefits, and impacts of using GHG adders to influence future procurement choices. IOUs are asked to discuss how an adder for carbon dioxide emissions might be used to incorporate externality costs from global warming that can be associated to fossil fuel use. A reasonable range of values should be discussed, from at least \$7/ton CO_2 to as much as \$25/ton.

QF Extensions

The IOUs are asked to assess potential impacts of extending all or nearly all QF contracts for the duration of the planning period. This scenario is an alternative to the individual IOU assumptions about QF renewals in their reference case, for which the IOUs are asked to submit estimates of future QF generation costs. The IOUs are not asked to estimate cost differences between their reference case and the blanket QF renewal scenario. The IOUs are mainly asked to indicate how future resource procurement might be affected given continued purchase of must-take energy from all existing QF resources.

Sensitivity to Natural Gas and Wholesale Electricity Prices

The Energy Commission requests that the IOUs provide the natural gas and wholesale electricity price estimates used in their analyses. IOUs are also asked to submit the information on natural gas and wholesale electricity price forecasts used in simulations. Wholesale electricity price estimates should be consistent with said gas prices. Natural gas prices should be based on current forward prices in the near-term, but may, at the utility's discretion, be based on a fundamentals model over the longer-term. Should such a model be used, any significant differences between forecasted prices and those indicated by current forward prices and their extrapolation should be explained. Should an IOU use yet another methodology for determining long-run gas prices, it should be explained in documentation which accompanies the price forecast.

The IOUs are asked to provide an estimate of long-run changes in natural gas and wholesale electricity prices, and how these two indices may affect the cost of meeting their load obligations. Bounding estimates should be based on prices in the tenth and ninetieth percentiles. The resulting effects on assumed wholesale electricity prices should reflect appropriate input price elasticities.

Major Uncertainties and Risk Analysis

The Energy Commission asks LSEs to provide narrative and qualitative assessments of how major uncertainties would impact either their reference case or their preferred resource plan. Each LSE should identify and list individual uncertainties that result in significant risk or opportunity. The major uncertainties to address are those affecting forecast loads, wholesale energy prices, and LSE resource portfolios. For each of these major uncertainties, LSEs are asked to calculate a set of individual sensitivities, much like the previous descriptions of scenarios. LSEs are not being asked to calculate sensitivities that address multiple uncertainty inputs, or to model all possible combinations of input uncertainties. This is not a requirement to conduct an integrated risk analysis that would address the sensitivities and probabilities of all uncertainties simultaneously. LSEs should focus on how their long-term resource plans can accommodate many different outcomes other than those forecast values specified or assumed on the CRATs and Energy Balance tables.

Each LSE is expected to evaluate risk according to its own unique positions, obligations, and strategies. Major uncertainty factors for most LSEs probably include proposed legislation, pending regulatory decisions, financial market requirements, and changes to California's energy markets. IOUs are expected to provide more risk analysis partly because they will be filing both a reference case and a preferred resource plan, and partly because they face greater uncertainty from the state's regulatory environment than other LSEs.

Numerous uncertainties, risks, and scenarios are involved with long-term resource planning. The following outlines reflect thinking of Energy Commission staff about key sources of uncertainty. These risks, and the management strategies to address those risks, will vary considerably among LSEs.

Core/Non-core – Departing Load

One of the largest uncertainties facing the state's IOUs is how future load obligations will be affected by policy decisions related to core/non-core, community choice aggregation, and municipalization. If IOUs procure supply resources in excess of those ultimately needed by IOU bundled customers, there may be a need to sell surplus energy in a buyers' market, or to dispatch utility-controlled capacity resources in a less efficient manner. Reducing or managing this risk in the face of load uncertainty may require a portfolio of resources with diverse durations.

IOUs are asked to evaluate a scenario under which IOU load falls as a result of future core/non-core policy decisions. The Energy Commission proposes that the IOUs submit a "low load" resource plan assuming 75% of customers with peak demand of 500 kW[12] or more will depart during 2009 – 2012 (30% in 2009, 15% in each of 2010 – 2012). Should an IOU believe that another Core/Non-core scenario provides additional information regarding the risks that it faces, it is encouraged to provide and evaluate that scenario.

An IOU may believe the straw man assumptions about load that departs to ESPs, CCAs, and Publicly Owned Utilities does not accurately reflect the risks and costs of over-procurement. If so, the IOU should explain this reasoning in the narrative report.

LSEs may have a residual obligation to serve customers who have or will depart from bundled service. LSEs may be the provider of last resort in cases where a Community Choice Aggregator or ESP becomes insolvent or incapable of delivering contractual supplies. LSEs are asked to identify how this possibility affects their resource planning, and to estimate what the risk premium costs might be for this implicit customer service responsibility.

Quantitative Analyses of Uncertainty

The foregoing subsections have discussed key uncertainties that the Energy Commission believes must be assessed. The nature of the assessment that makes the most productive use of parties' resources is less clear. The Energy Commission

[12] It is assumed that individual customers at different sites will not to be allowed to aggregate their loads in order to reach the threshold of 500 kW.

does not believe all of these uncertainties merit a complete simulation of how resource plans might be implemented, optimized, and hedged to guard against costly risks. Some uncertainties could substantially impact how reference case resource plans are implemented, and therefore merit a more integrated analysis. Other uncertainties with less potential impact may be illuminated with more simplistic sensitivity studies.

These instructions do not purport to address how the quantitative assessment of uncertainty of supply and demand should be addressed. Each LSE addresses uncertainty and risk according to its own obligations, positions, strategies, assessments, and decision criteria. A common set of assumptions and expectations could be developed in order to provide input to the determination of what assessment techniques could or should be used. Greater clarity is needed about what must be decided and by whom so that policy and regulatory decisions can be made with smoother integration and less overlap. Greater understanding and consensus is needed about how decision criteria can incorporate risk assessments, including weighing of attributes that may be suitable and appropriate for tradeoffs. Energy use clearly affects environmental health, public health, and economic health. How tradeoffs might be made involving reliability, rates, and environmental performance, however, is much less certain. How costs in these three areas might be quantified in support of policy-making is far less clear. Once alternative assessment techniques are better understood, the range of likely benefits and the all-in "costs" of deploying various supply and demand strategies and preferences may appear suitable for quantitative analysis.

Major Transmission Upgrades

The reference case should include an assessment of transmission constraints that may adversely affect the ability of delivering planned resources to forecast loads. IOUs are asked to submit information on how desired upgrades to the bulk transmission system would affect their preferred resource plans.

If the reference case submitted by an LSE assumes an upgrade to the bulk transmission grid that has yet to receive regulatory approval, the Energy Commission also requests submittal of a modified version of the same resource plan without the upgrade. Essentially this means a "with and without" analysis. The reference case analysis should detail the changes in the direct costs of meeting load and reserve obligations that the upgrade makes possible, assess any additional benefits that the upgrade may provide, and explicitly state the changes in assumptions (*e.g*., import capability and quantities, changes in wholesale prices) in the two cases.

Deliverability

Effective resource planning requires that energy generated by projected resources be deliverable to load; the requirement that the IOUs evaluate deliverability in their long-term procurement filings was imposed in R.04-04-003.[13] Accordingly, the Energy Commission intends to request information from the IOUs and ESPs on their projected ability to meet expected peak loads given both inter- and intrazonal transmission constraints.

The ongoing resource adequacy and procurement proceedings at the CPUC have yet to resolve how deliverability is to be evaluated; it is therefore not possible to fully determine which resources are deliverable to load. This makes it difficult to determine what data and analysis is necessary to provide policymakers with useful information regarding deliverability.

The Energy Commission could simply request load forecasts and resources within the relevant ISO local reliability areas from each of the IOUs and ESPs, but this may not provide a complete set of useful information. Some deliverability concerns arise from intrazonal transmission constraints that are not associated with local reliability areas. These may require projections of loads and available resources within areas that remain to be defined.

The Energy Commission proposes revisiting this issue at such time that consultation between the Energy Commission, CPUC, ISO, and IOUs can provide additional direction regarding the procurement constraints that need to be met by the IOUs to ensure local reliability, as well as the data needed to assess whether a given resource plan meets local reliability requirements.

[13] See, for example, the Interim Order Regarding Electricity Reliability Issues dated June 28, 2004.

Planned Transmission Facilities

What Must Be Filed

The descriptions and examples below specify the information categories, scope, and reporting requirements. Since the majority of this information will be narrative text, LSEs are asked to submit this information in Word or Adobe electronic format.

All transmission-owning LSEs are required to file a general description of their transmission planning and permitting process. Each LSE is required to file a 10-year transmission plan. This plan should describe in detail all of the transmission facilities over 100 kV that the LSE needs to meet applicable reliability and planning standards. This plan should include the identification of all proposed, approved, and committed transmission facilities. Where other transmission resources are planned to either reduce congestion or increase access to generation resources these facilities should be described in detail as well.

All transmission-owning LSEs are required to file data on specific projects identified in their 10-year transmission plans. The amount of detail required for each facility description is described in transmission forms 1, 2 and 3. The descriptions should include a general discussion of corridor needs and how the planned transmission facilities will be used by the LSE.

Transmission-owning LSEs are required to file a twenty-year transmission plan that discusses more general or generic transmission needs and strategies. This plan should highlight any steps that could be taken now to assure those transmission needs are met.

LSEs are required to identify any potential corridor needs vital to the long-term development of strategic transmission projects. LSEs are asked to identify possible corridors that are not yet associated with specific transmission projects and that could be designated as transmission corridors. In addition to the strategic transmission projects, LSEs should include a description of the studies used to define the strategic projects. The description of the transmission projects identified in the 10-year plan and other strategic projects could include the effect of the resource on the LSE's ability to:

- Meet reliability and/or planning criteria
- Access resources needed to meet resource adequacy requirements
- Access renewable generators
- Lower the cost of serving loads
- Relieve congestion

Completion of Forms

Transmission Form 1 must be completed for all bulk transmission projects identified in the 10-year plan over 100 kV planned to be operational between January of 2005 and December of 2016.

Transmission Form 2 must be completed for all bulk transmission projects identified in the 10-year transmission plan over 100 kV and costing more than $20 million planned to be operational between January of 2005 and December of 2016.

Transmission "Form" 3 must be completed for all bulk transmission projects identified in the 10-year transmission plan over 100 kV and costing more than $100 million planned to be operational between January of 2005 and December of 2016.

Filers may submit documents filed at the CPUC or CA ISO in lieu of re-formatting existing information into the templates or categories prescribed for Transmission Form 1 and Transmission Form 2, provided that the information required as described in these instructions is provided. Filers may submit documents filed at the CPUC or CA ISO along with supplemental information needed to meet the requirements of Transmission "Form" 3.

Transmission Form 1: Projects over 100 kV

This form must be filled out for all bulk transmission projects over 100 kV. A blank worksheet is provided as following these instructions.

Project Name
Include the geographic endpoints, and the primary project facilities.

Location
Include the project location, county, city and local reliability area, if applicable.

Project Description
Should a complete list of the major facilities required for the project. Where the designated project requires other transmission system reinforcements, those should be listed as part of the project.

Rating
Provide the installed ratings (kV and MVA) of facilities involved in the project.

Cost
Estimate project cost in millions of dollars.

Date in Service
Provide the expected date of commercial operation.

Purpose and Benefit
Describe what the project will accomplish, enable, or better facilitate. Note significant changes or improvements expected for the transmission network. List the qualitative and approximate quantitative benefits expected to be provided by the project, and who will receive those benefits.

Potential Issues
Briefly state any issues that may delay or prevent the project from operating on the expected date of commercial operation.

Also as an attachment, provide the modeling specification for the project or the characterization of the project in the GE PSLF model.

Transmission Form 1 Template
Data for Bulk Transmission Projects over 100 kV

PROJECT NAME	LOCATION	PROJECT DESCRIPTION	RATING	DATE IN SERVICE	COST $MM	PURPOSE & BENEFIT	POTENTIAL ISSUES

Transmission Form 2: Projects over $20 Million

Transmission Form 2 must be completed for all bulk transmission projects that are rated at or above 100 kV and costing more than $20 million. A sample submittal for Form 2 projects follows these instructions.

Project Name
Provide the general project name.

Project Description
Provide a complete description of all the facilities associated with the project and the expected in-service date. If the project was identified in a publicly available annual report, indicate the title and year of the report.

Project Background and Purpose

Provide significant detail on the background for the project including a description of the region and the conditions affecting the need for the project. Provide a list of the overloads and/or congestion problems the project addresses, and how these loadings and congestion problems will be reduced by the project. Briefly describe the expected project benefits in qualitative and quantitative terms, and identify who will receive those benefits. Describe how transmission system changes will serve and integrate with expected development of generation facilities including renewable generation facilities that meet RPS goals.

Project Alternatives

Discuss the alternatives to the project including both transmission and non-transmission options. If non-transmission alternatives were not considered, explain why they weren't considered. For the alternatives, provide rough cost and benefit estimates, and the reasons why alternative projects (and the "no project" option) were not chosen.

Study Assumptions

Briefly describe the major forecasts, beliefs, and trends that were assumed in studies analyzing the project. Where the load and resource assumptions differ from the reference case provide in the demand and supply forms, briefly describe the differences and their expected impact on the need for the project. Include the name of the WECC or other load flow data, and any substantive changes to the load and resource assumptions in the load flow case.

Key Uncertainties

Discuss potential problems and conflicts that may slow or prevent the development of the project, especially including permitting, potential corridor related issues, environmental concerns, and financing.

Project Status/Schedule of Milestones

Provide a list of key project milestones and a rough estimate of the month they are expected to be completed. For milestones that have already been met, provide the completion date.

Modeling information

Provide the GE PSLF (or other similar model) description of the project.

Diagram of the Project (Scope Diagram)

Provide a schematic line diagram of the project including important major geographic references, such as cities and substations near the project. This diagram should provide enough detail to adequately describe the project. (See Attachment 3 for a diagram example).

Transmission Form 2 Example

The following is a hypothetical example that illustrates information to be reported for a bulk transmission project over 100 kV and costing more than $20 million.

Project Name

Metcalf-Moss Landing 230 kV Reconductor

Project Description

Reconductor approximately 35 miles of the Metcalf-Moss Landing 230 kV double circuit tower-lines with 954 SSAC conductors and upgrade associated line terminal equipment to accommodate the higher capacity ratings for the Metcalf-Moss Landing 230 kV double circuit tower-lines. It is estimated that the project will cost approximately $29 million.

Project Background and Purpose

Bay Area load is served by a combination of in-area generation and power imported via three major import paths: from the Vaca-Dixon, Tesla and Moss Landing Substations. A general representation of this region of the Bay Area transmission system is shown in Figure 1. A stakeholder study entitled “Bay Area Bulk Transmission Reliability Improvement Project” was completed by PG&E in 2003. In general, the study results indicated that a long-term need existed to reinforce the 230kV transmission path from Moss Landing substation to serve future load growth in the Greater Bay Area. As such, the study recommended alternatives to increase the ability to move power from the Moss Landing substation into the Greater Bay Area.

The need to address the Metcalf – Moss Landing 230kV path is primarily related to inadequate transmission line capacity in conjunction with generation interconnected at the Moss Landing facility. Approximately 2,600 MW of generation is interconnected at Moss Landing. Dispatching all this generation simultaneously pushes a significant amount of power from Moss Landing to Metcalf. Under certain single contingency conditions, the Metcalf-Moss Landing 230kV lines will overload without the use of a special protection scheme. That scheme trips 1100 MW of Moss Landing generation that is connected to the Moss Landing 230kV bus if power flows across the Metcalf – Moss Landing 230kV lines exceed their thermal capability. At the present time, tripping this amount of generation is sufficient to address the overload conditions. However, by 2006 and beyond, generation tripping will become insufficient to mitigate these thermal overloads, and firm load shedding would be required without this project. ISO planning standards do not allow firm load to be shed for single contingencies. Therefore, additional transmission reinforcement is required before 2006.

The Metcalf-Moss Landing Reinforcement Project will avoid a requirement for load dropping due to a single contingency outage. The Project will also eliminate the requirement to trip 1100 MW of generation until the year 2017. Further, the Project significantly reduces the amount of generation tripping and load dropping required to protect against worst double contingency outages. Lastly, the Project significantly improves the overall power import capability to the Bay Area, thereby reducing overall production costs across the Greater Bay Area.

Project Alternatives

In general, the "Bay Area Bulk Transmission Reliability Improvement Project" study recommended the following reinforcement alternatives for this problem:

1. Reconductoring the Metcalf-Moss Landing 230 kV lines with 954 ACSS conductor.
2. Build new Metcalf-Moss Landing # 3 & 4 230 kV lines. Reconfigure the existing Metcalf-Moss Landing # 1 & 2 lines. Also reconfigure the Hicks-Metcalf and Vasona-Metcalf 230 kV lines to the Hicks-Moss Landing and Vasona-Moss Landing 230 kV lines.
3. Build a new Metcalf-Moss Landing #2 500 kV line.

Since all three alternatives will mitigate the reliability violation in the area, an economic assessment of these alternatives was conducted to facilitate the selection of the best alternative for CA ISO ratepayers.

The economic assessment of the three transmission alternatives analyzed factors relating to equivalent facilities, generation tripping, load dropping, loss savings, and generation-related benefits. The assessment of generation related benefits were included production cost savings resulting from an increase in overall Greater Bay Area import capability, leading to a decrease in overall generation costs. Changes in the Bay Area generation production costs and import costs stemming from the increased Bay Area import capability were simulated using a production cost model (MultiSym). Model runs using Monte Carlo draws demonstrated increased opportunities to utilize low-cost generation, when available).
Three scenarios were studied:

- A baseline production cost simulation benefit (or average hydro scenario),
- A high production cost simulation benefit (or wet hydro scenario), and
- A low production cost simulation benefit (or dry hydro scenario).

Due to its low capital cost, and high sensitivity to production cost, Alternative 1 (reconductor) returned the best benefit-cost ratios among the three reinforcement options. Alternative 1 is the only one with a benefit-cost ratio greater than one for all three generation scenarios.

Study Assumptions

Two sets of base cases were developed from the 2002 base case series (names here) for use in this study. The first base case modeled projected year 2007 system conditions with about 9,700 MW of Greater Bay Area demand. (This is the projected load for a 1-in-10 year adverse weather condition for 2007 from the 2002 forecast). The second base case modeled projected year 2012 system conditions, except that the Greater Bay Area demand was assumed at 12,000 MW (which is the projected 1-in-10 load for 2018 of the 2002 base case).

The CA ISO Grid Planning Criteria were used to assess this project. In conformance with CA ISO's Planning Standards, Potrero Unit No. 3, Potrero Unit No. 6, and Oakland PP Unit No. 1 were modeled off line in the study cases.

Key Uncertainties

Costs may increase if additional construction is needed. Generation curtailments may be required during construction. Environmental concerns, which will be identified during the permitting phase of the project, may require avoidance, reductions, mitigation, or offsets to potential adverse impacts. For example, clearing of knobcone pine for right-of-way work across the Santa Cruz Mountains will probably require contributions to enhance or restore comparable knobcone pine habitat elsewhere in the Santa Cruz Mountains. Studies of potential marbled murrelet habitat will be required where the existing T-line crosses land within 5 miles of predominantly redwood mature forest habitat. There could be interactions with other projects that haven't been accounted for.

Project Status/Schedule of Milestones

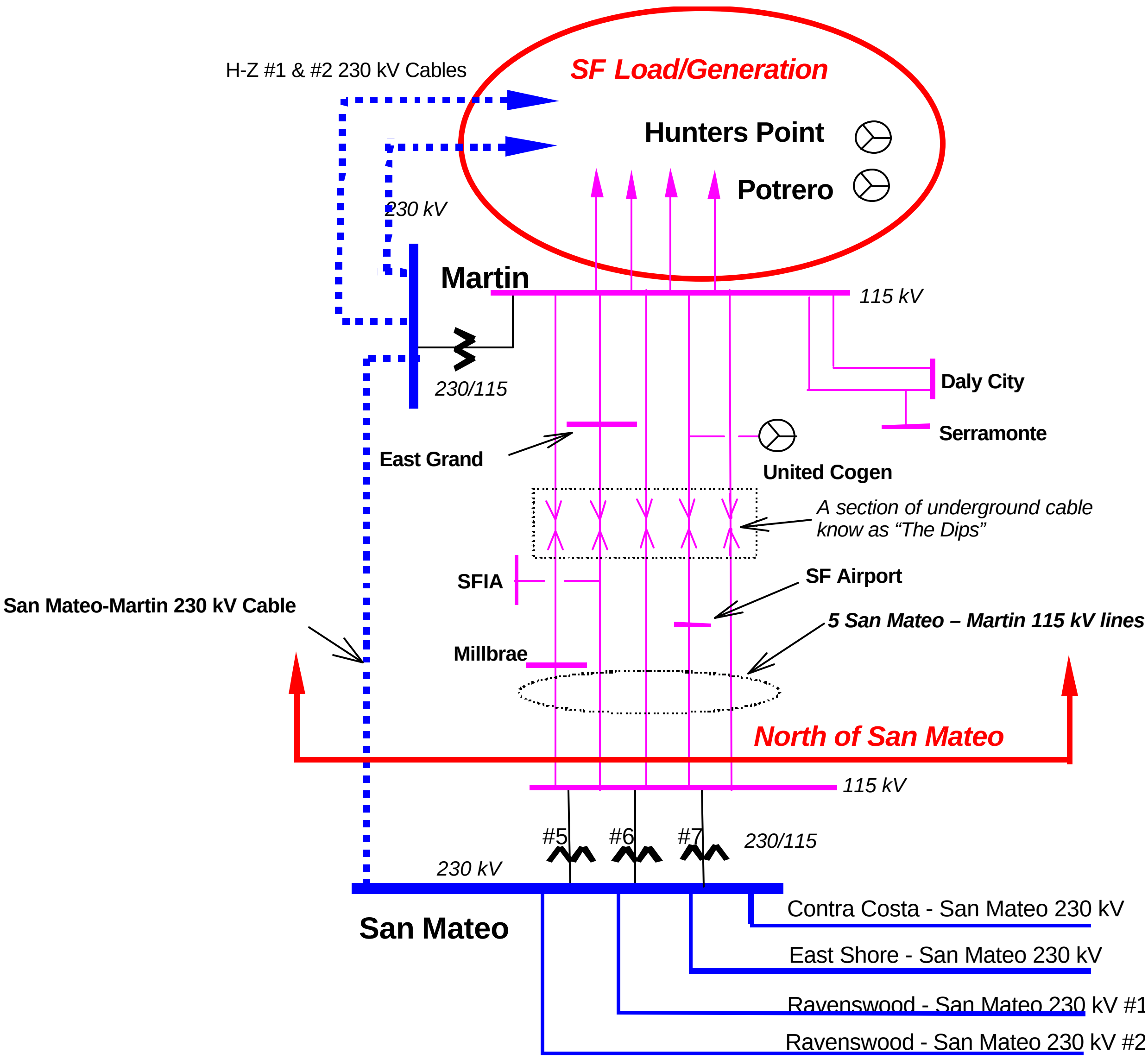
- CA ISO Needs Analysis – April 2003
- Economic Assessment – November 2003
- Environmental Impact Report (EIR) filed – June 2004
- Construction and Operations Contracts – September 2004
- Financing Secured – December 2004
- Design – March 2005
- CEQA Permits (or Negative Declaration) issued– March 2005
- Construction initiated– May 2005
- Construction completed – September 2005
- Commercial Operation Date – October 1, 2005
- Date Needed for Reliability – June 1, 2006

GE PSLF Modeling Information

OLDSECDD 30735 30755 1 RPU=0.007253 XPU=0.52162 MVA1=805 MVA2=843

Schematic Line Diagram

Transmission Form 2 asks for a schematic line including major geographic references such as cities and substations near a project. This following example is from Staff Local Systems Effect Testimony for the Potrero Power Plant Unit 7 Project for a project on the San Francisco Peninsula Transmission System.



Transmission "Form" 3: Projects over $100 Million

For large projects, the Energy Commission requires planning studies showing the project is needed for system reliability, that the project provides economic benefits, or that the project is needed to meet renewable resource targets. These studies should propose and consider alternatives to address the problem, including non-transmission alternatives. A specific form and format for these studies is not prescribed.

At a minimum the study for a large project should report the following:

- Clearly describe the problem that the project addresses.

- Define or describe the criteria that will be used to evaluate the project and potential alternatives.

- Highlight and elaborate the key transmission assumptions that help justify this project. Explicitly identify all assumptions used to analyze the project where these assumptions differ from the reference case filed in the Supply Forms (for LSEs who own transmission). Explain why there are differences. Estimate the expected impact on the study results of the changes from the reference case.

- Identify prospective costs and benefits from the project, including some description of who benefits and who pays. Estimate total development costs for the project and for project alternatives, including estimated annual carrying charges. Discuss the social discount rate used and the reason it was chosen.

- Describe the strategic benefits provided by the project (or its alternatives) as revealed by analytical studies. Discuss the insurance benefits of the project and alternatives. If it is relevant, indicate potential effects of the project (and alternatives) on local reliability needs and must-run costs in California.

- Discuss in detail how the project (and alternatives) would affect transmission congestion in California and on other WECC paths. Assess how this project (and alternatives) relates to the need for other planned transmission facilities.

- Identify system-level benefits of the project (and alternatives) such as how the project would enhance (or maintain) the ability of the network to meet WECC or other control area reliability and planning criteria.

- Summarize and reference the load flow case studies and analysis for this project. If this case is not available to stakeholders, submit the load flow case study as well. List other projects and case studies beyond the specified case.

- Describe the source of the load forecast, the vintage, and explain how it differs from the reference case filed in the Demand Forms and Instructions. Where several load forecasts (on/off peak, 1-in-5 or 1-in-10) are used, list them all.

- Identify the source and vintage of key energy supply assumptions including new generation, retiring generation, and hydroelectric availability. For LSEs, describe how these assumptions may differ from the reference case information for generation described in the Supply Forms. Clearly identify which generation scenario is embodied in the transmission study assumptions.

- Provide the fuel prices used to calculate the costs and benefits of the project and its alternatives. Connect these fuel price forecasts to simulated electricity production costs. Estimate cost/benefit totals in both real 2005 dollars and in escalated values. Where multiple fuel prices were used, include those as well.

- Provide a narrative description of the key uncertainties that will affect and influence anticipated project benefits. These uncertainties could include the location and size of future loads, the location and quantity of future generation, and fuel prices. Describe sensitivity studies that analyzed project benefits under various load, fuel, and resource assumptions. Describe modeling and analytical tools used to develop and evaluate the project.